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ACT (Available Control Technology) for Stationary NOx Sources

Acurex Corp.
Mountain View, CA

Prepared for

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16. ABSTRACT

Engineering evaluations of stationary source NO_x controls were conducted and are reported here to support EPA Region IX in determining whether the NO_x emission control rules in the EPA approved State Implementation Plan (SIP) and the recently submitted SIP revisions for the Los Angeles and San Diego areas represent an adequate level of NO_x emission control for stationary sources. This report documents the following: A summary of the stationary source NO_x emission control rules contained in the SIPs; "Available Control Technology (ACT)" specifications for NO_x sources in these areas; and a summary of NO_x rules for other areas in the U.S. The ACT specification includes estimates of baseline and controlled emissions levels, the limitations and operational impacts, and the control costs associated with ACT. Sources considered include utility and industrial boilers, gas turbines, internal combustion engines, and industrial processes. Control technologies include several levels of combustion modifications and post combustion cleanup.

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SECTION 1
INTRODUCTION

Both the South Coast Air Quality Management District (SCAQMD) and the San Diego County Air Pollution Control District (APCD) have been designated by EPA as nonattainment areas for the NO_2 National Ambient Air Quality Standard (100 $\mu g/m^3$, annual average). NO_2 nonattainment plans for these areas have been submitted to EPA, and EPA is required to determine whether the NO_x emission control rules contained in the plans and the EPA approved State Implementation Plan (SIP) represent an adequate level of NO_x emission control.

To support this determination, EPA initiated the study summarized in this report to identify the availability, control effectiveness, cost and limitations of stationary source retrofit NO_x controls.

The objectives of this study were to:

- Summarize the stationary source emission control rules contained in the SIP
- Identify "available control technology" (ACT) for source categories affected by the SIP; specify
  - Emission reduction
  - Limitations and operational impacts
  - Control costs
- Identify ACT for source categories not affected by the SIP; specify
  - Emission reduction
  - Limitations and operational impacts
  - Control costs
- Summarize NO_x control regulations for other areas in and outside of California.

For the purposes of this study, the term "available control technology (ACT)" is defined as technology for which at least one successful test has been performed on full scale field equipment. (Definitions for this term and others are found in the Appendix C Glossary of Terms.) Thus emerging techniques for which only pilot scale data are available were excluded from the ACT designation. At the same time, designation of a technology as "available" in this report should not be construed to mean that the implementation of such control techniques is necessarily reasonable on a long term basis. Additional long term tests on a diversity of equipment designs, evaluation of potential operational impact, and cost impact evaluation may be necessary to qualify a particular control technique as "reasonable" or as "demonstrated technology". In this regard, it is emphasized that the degree of difficulty in reaching a specified emission level with retrofit NO_x controls is very dependent on site specific factors such as equipment design, age, and plant layout. Thus achieving a given emission level may be routine with some sources while being very difficult or impractical with others. The ACT designations in the report are not intended to be associated with any or all sources in the SCAQMD or San Diego APCD. Rather, the designations are generic for the representative design types for which control data are available. In some cases, source specific constraints such as space limitations and combustor configuration may preclude or severely limit the application of retrofit control technology identified as ACT.

Section 2 of the report summarizes the status of available control technology for source categories in the SCAQMD. Section 3 gives a discussion of control techniques for each major equipment design and fuel combustion category, the estimated costs and cost effectiveness of control technology and a nationwide survey of NO_x emission control rules. A glossary of terms and a summary of the methodology and assumptions used in the text are given in the Appendix.

SECTION 2

SUMMARY

In the South Coast Air Quality Management District, the stationary sources affected by SIP NO_x emission limits are almost exclusively utility boilers. The largest of these boilers -- above about 600 MW maximum thermal input -- are regulated to a limit of 125 ppm NO_x (at 3 percent O_2) for gas firing, and 225 ppm for oil firing.

A survey of Available Control Technology indicates that achieving these limits requires essentially the full capability of retrofit combustion modification technology. The cost effectiveness to reach these limits using combined combustion modifications are estimated from utility control implementation applications. The cost effectiveness is \$100 to \$410 per ton (110 to 452 \$/Mg) of NO_x reduced per year for gas firing, and \$305 to \$1240 per ton (336 to 1366 \$/Mg) for oil firing.

Additional emission reductions may be possible with emerging control techniques which are more stringent than conventional combustion modifications. Noncatalytic ammonia injection may reduce NO_x by an additional 35 to 40 percent. This produces a differential cost effectiveness of \$4000 to \$10,000 per ton (4400 to 11000 \$/Mg) for gas units and \$3000 to \$5000 per ton (3300 to 5500 \$/Mg) for oil units. Selective catalytic reduction may reduce NO_x up to approximately 90 percent over combustion modifications. A differential cost effectiveness of \$15,000 to \$25,000 per ton (16500 to 27500 \$/Mg) for gas firing and \$9000 to \$13,000 per ton (9900 to 14300 \$/Mg) for oil firing is estimated for this measure.

The SIP emission limits for intermediate sized utility boilers (approximately 150 to 600 MW thermal input) are higher -- 225 to 300 ppm for gas firing and 325 to 400 ppm for oil firing depending on boiler capacity and county within the SCAQMD. These limits are generally achievable by combustion modification ACT at a cost effectiveness comparable to the larger boilers. Additional reductions with combustion modification may be possible with some units but the cost effectiveness is highly dependent on specific unit characteristics such as burner/firebox design, the age of the unit and the combustion controls available.

Available control technology was also surveyed for sources which are not currently affected by the SIP. Small utility boilers with a capacity less than about 150 MW thermal input are currently not subject to SIP emission limits and could, in principal, achieve emission reductions with combustion modification ACT. However, the amenability to reduction is very dependent on equipment design, particularly for older units. Also, for units on standby use, the cost per ton reduced would be high due to the low load factor.

Gas turbine NO_x emissions can be reduced approximately 50 percent through the use of water injection. The cost effectiveness is strongly dependent on whether the turbine is used only for peaking power or for more sustained loads. For peaking, with an assumed load factor of 6 percent, the average cost per ton reduced per year is estimated at $9,000 ($9900/Mg) for oil firing and $12,000 ($13,200/Mg)for gas firing. At the other extreme, with an assumed load factor of 90 percent, the average cost effectiveness is $1700 per ton ($1870/Mg) for oil firing and $1200 per ton ($1320/Mg) for gas firing.

The retrofit control technologies for the remaining source types -- industrial boilers, internal combustion engines, petroleum refinery heaters, and industrial processes -- are generally at an earlier stage of development. This factor, combined with the small capacities and diversity of design types of these sources, causes a wide range of uncertainty in estimated emission reductions and estimated control cost effectiveness. Some sources, due to equipment design or physical space constraints, may be very difficult to control on a retrofit basis. In many instances, the cost effectiveness for controlling NO_x emissions from industrial boilers by the use of combustion modifications is of the same order as adding noncatalytic ammonia injection or selective catalytic reduction to utility boilers. For internal combustion engines, control to a 20 to 40 percent level has a corresponding cost of $200 to $4000 per ton ($220 to $4400/Mg).

The 1979 State Implementation Plan (SIP) revisions for the SCAQMD area were recently submitted to EPA. These revisions, while containing no new NO_x control rules, do recommend the implementation of NO_x retrofit emission control measures for all of the ACT source categories identified in this study and not presently affected by the SIP, except gas turbines for which no additional controls are recommended in the SIP revisions.

SECTION 3
DISCUSSION

The data and information presented in this section are related to the SCAQMD stationary source SIP NO_x retrofit rules and the emission source types affected by these rules. No additional NO_x retrofit rules are contained in the July 1979 SIP revisions. NO_x emission control data for SCAQMD area source types not affected by the SIP NO_x retrofit rules and for which control technology information is available is also presented.

The San Diego stationary source SIP NO_x retrofit rule requirements in relation to the affected emission sources are not discussed in detail. The reason is that the San Diego rule appears to reflect or require the application of the more stringent levels of ACT. A summary and a discussion of the SCAQMD and San Diego SIP NO_x retrofit rule requirements are presented in subsection 3.1.

The San Diego SIP NO_x retrofit rule covers a wide range of fuel burning sources (i.e., >50 x 10^6 Btu/hr (15 MW) heat input). Further it limits these sources to an emissions concentration level of 125 ppm NO_x (at 3 percent O_2) for gaseous fuel combustion and 225 ppm NO_x for liquid and solid fuel combustion. Table 3-1 shows that the SCAQMD rules require fuel burning sources in Orange and Los Angeles Counties (essentially utility boilers) to meet these limits if those sources are greater than 2150 x 10^6 Btu/hr (630 MW) heat input capacity. For Riverside and San Bernardino Counties, the cutoff is 555 x 10^6 Btu/hr (163 MW) heat input capacity.

The EPA New Source Performance Standards (NSPS) for fossil fuel-fired steam generators only affect generators greater than 250 x 10^6 Btu/hr (73 MW) heat input capacity. The NSPS limits NO_x emissions from gaseous fueled steam generators to 86 ng/J of heat input (approximately 168 ppm) and from oil fueled steam generators to 130 ng/J

A number of terms are used in this report (particularly the terms describing the ACT) whose use and definitions may not be obvious. Appendix C contains a glossary of such terms and the definitions related to their use in this report.

3.1 STATE IMPLEMENTATION PLAN NO_x RETROFIT RULE EMISSION LIMITS

Table 3-1 presents a summary of NO_x emission limits contained in the EPA approved California SIP relating to stationary source retrofit control applications for the Southern California Air Quality Management District and San Diego County APCD areas. Emission limits specified by the Federal NSPS for fossil fuel-fired steam generators are also presented in the table. The table contains the regulatory description of the source categories subject to the emission limits.

This study is for the purpose of analyzing the feasibility and appropriateness of applying NO_x retrofit emission controls. The NSPS emission control requirements are presented here only for information and comparative purposes since these limits apply to only new sources.

No additional NO_x emission retrofit control rules were contained in the recent State of California submitted SIP revisions of July 1979 and thus only the NO_x retrofit rules contained in the present EPA approved SIP are summarized.

3.2 NO_x AVAILABLE CONTROL TECHNOLOGY RELATED TO SOURCES AFFECTED BY SIP RETROFIT RULE EMISSION LIMITS

Figures 3-1 and 3-2 present estimates for the baseline emission level ranges for the oil and gas fired utility boilers affected by the SCAQMD and San Diego area rules, as well as the emission limits to which such baseline emissions must be reduced or maintained in the SCAQMD and San Diego areas. Because of the relatively large capacity cut off of the SCAQMD, NO_x retrofit rules (i.e., $>500 \times 10^6$ Btu/hr or 147 MW) only the larger boilers in the SCAQMD area tend to be controlled and these larger boilers are almost exclusively found in the electric utility industry. Several carbon monoxide (CO) fired boilers in the petroleum refining industry in the SCAQMD area apparently have a heat input capacity greater than 500×10^6 Btu/hr (147 MW) and thus should be within the jurisdiction of the SCAQMD rule. However, apparently these sources are in compliance with the rule emission limits due to the low NO_x emission

TABLE 3-1. SIP NO_x STATIONARY SOURCE RETROFIT AND FEDERAL NEW SOURCE PERFORMANCE STANDARD EMISSION LIMITS

Rule:	474				68		68	Federal NSPS
Affected Area:	L.A., Riverside & San Bernardino Cos.			Riverside & San Bernardino Cos.	Orange Co.		San Diego Co.	Nationwide
Category:	Fuel Burning Equipment			Steam Generating Equipment	Fuel Burning Equipment		Fuel Burning Equipment	Fossil Fuel-Fired Steam Generators
Capacity: Max. Heat Input -10^6 Btu/hr (MW)	555 to <1786 (163 to <523 MW)	1786 to <2143 (523 to <628 MW)	$\geq$2143 ($\geq$628MW)	$\geq$555 ($\geq$163M)	> 500 to 2150 (>147 to 630 MW)	$\geq$2150 ($\geq$630 MW)	$\geq$50 ($\geq$15 MW)	> 250 (>73 MW)
Emission Limit (ppm NO_x, 15 min. avg., dry, at 3% O_2 by fuel type):					*	*	**	***
Gas --	300	225	125	125	225	125	125	168
Liquid & Solid --	400	325	225	225	325	225	225	231****

*Not calculated as dry air

**Exceptions to these limits are provided for certain equipment used in the testing of stationary turbine engines

***The NSPS emission limits are expressed in terms of "Mass of NO_x/unit of heat energy input" and the assumptions and calculation procedure used to convert these limits to ppm as shown in the Table are found in Appendix A

****Liquid fuel only

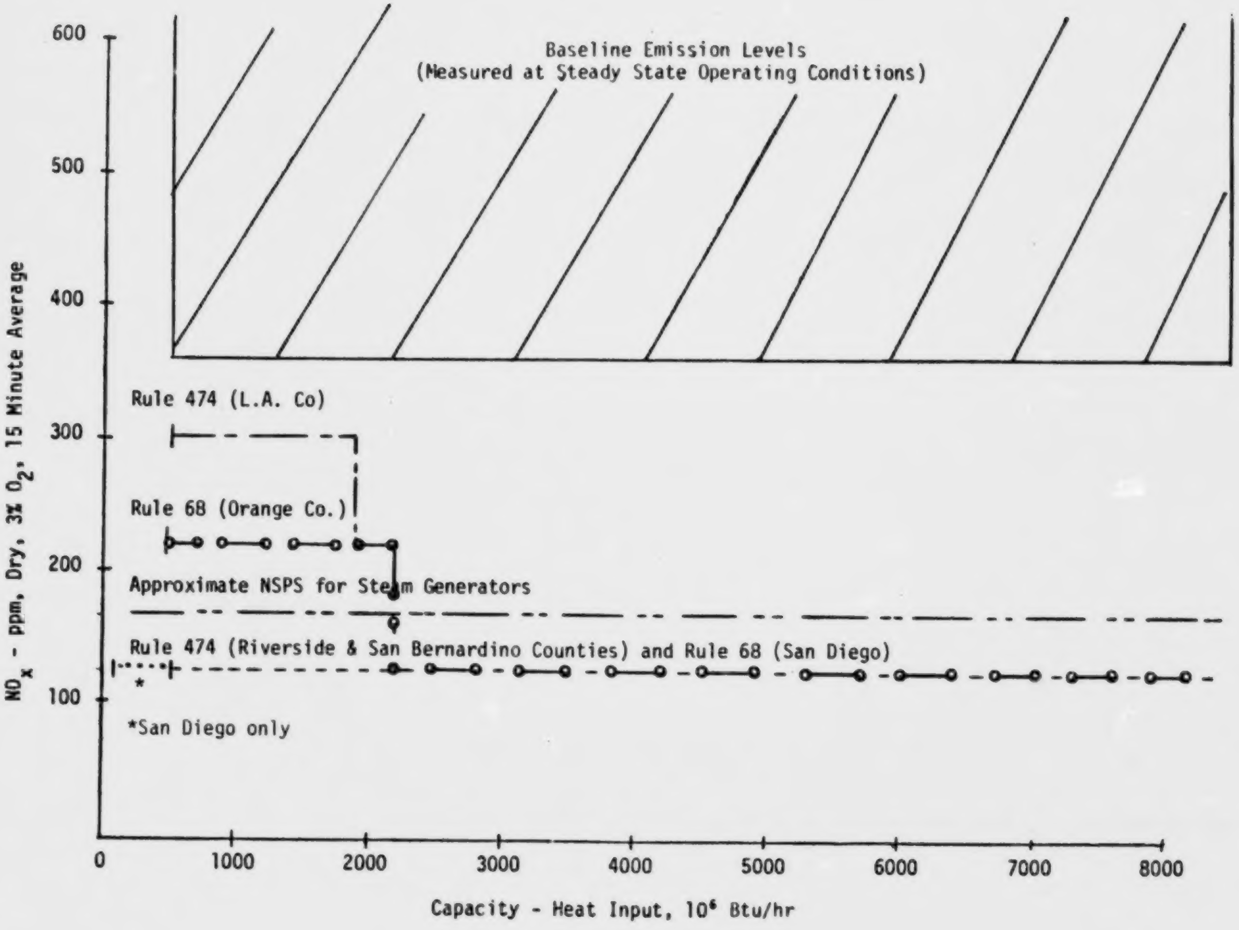

Figure 3-1. Gas-fired utility boiler capacity versus baseline ACT and NSPS NO_x emission levels.

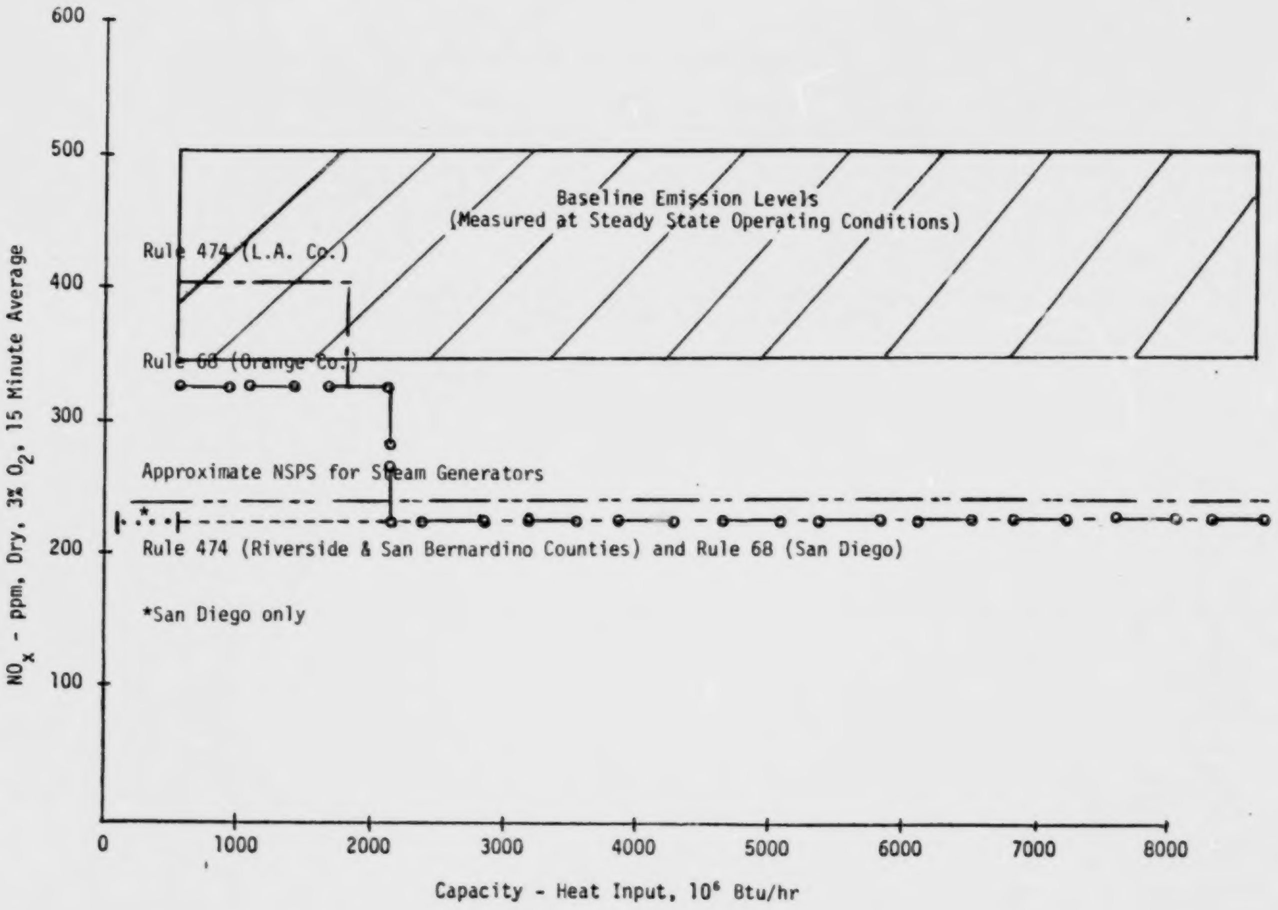

Figure 3-2. Oil-fired utility boiler capacity versus baseline ACT and NSPS NO_x emission levels.

levels of CO combustion. If control is required it may be possible to apply utility boiler type controls.

As previously pointed out, the SCAQMD area NO_x retrofit rules essentially affect the control of utility boilers. Also, the data available for sources with a heat capacity greater than 500 x 10^6 Btu/hr is limited to utility boilers. The available NO_x emissions retrofit control data for those source subcategories affected by the SCAQMD NO_x retrofit control rules is presented in Tables 3-3-A through 3-3-L. These control techniques are referred to as ACT. ACT is defined for an emission subcategory if adequate data for at least one test or application of the technology on full scale field equipment is available.

The San Diego County Air Pollution Control District (APCD), in a letter to EPA Region IX, commented that two ACT type NO_x emission control techniques were being applied to certain utility boilers in San Diego County to meet APCD emission limits. These control techniques involve the bypassing of the air preheater (i.e., reduced air preheat) in at least one utility boiler and the co-firing (or split fuel-firing) of residual oil and natural gas in another utility boiler. The split fuel-firing was reported by the APCD to result in some cases in NO_x emission levels that are lower than those that would occur from the use of natural gas alone. In all cases split fuel-firing resulted in emission levels lower than would result if the fuels were fired separately.

Test data were not presented for the air preheater bypass control application. Test data were presented for the split fuel control applications which showed an average NO_x concentration of 106 ppm (dry at 3 percent oxygen). Base case (i.e., uncontrolled) emission levels were not available, however, and thus these test results were not presented in Tables 3-3-A through 3-3-L. A conversation with APCD staff indicated that the split fuel boiler and burners were installed in 1974 and probably included the minimum or basic state-of-the-art NO_x control technology and techniques (e.g., low excess air) available at that time for new boilers.

The San Diego Rule 68 emission limits (125 ppm for gaseous fuel and 225 ppm for liquid fuel) are the same as those for which ACT is discussed for the SCAQMD area rules in Tables 3-3-E and 3-3-F, Tables 3-3-G and 3-3-H, and Tables 3-3-K and 3-3-L.

Following is a discussion and explanation of the information presented in Tables 3-3-A through 3-3-L:

- The first five columns in the tables relate to the NO_x SIP retrofit rule requirements and categorization. A table is constructed for each rule emission limit category. For example, Table 3-3-A for Rule 474 describes ACT that relates to the emission level specified by Rule 474 in Los Angeles, Riverside, and San Bernardino Counties, for fuel burning equipment with a heat capacity of 555 to $<2143\ 10^6$ Btu/hr (163 to <523 MW) using gaseous fuel. A summary of this information for each table is found in the "key" (Table 3-2) just preceeding these tables.
- The "Emissions" columns describe the emissions range in ppm for the "Base" case (i.e., uncontrolled) levels and for the "Controlled" case. The "Controlled" case identifies the emissions range associated with the ACT described in the "Available Control Technology" column. The average ppm concentration reduction expressed as a percent is also shown in the "Emissions: Controlled" column. The reported percent concentration reduction is average in that it is the reduction from the base case that can be expected by application of the ACT on an average utility boiler.
- The ability of the ACT to meet or exceed the rule emission limits is referenced by a numerical rating of 1, 2, or 3 found in the "Available Control Technology" column, and the significance of these ratings is discussed in the footnotes of the tables
- Comments describing the ACT application, its limitations and qualifications are found in the "Application Comments" column
- The reader should be alert to the fact that the SIP NO_x emission limits identified in the "Emission Limit" column are 15 minute averages, while the emission levels shown in the "Emissions Base" and "Emissions Controlled" columns are measured at steady state operating conditions. It is possible that such a 15 minute average emission limit could be exceeded by the controlled equipment during start-up or during load fluctuation periods, even though the steady state emission level would not exceed the rule 15 minute average emission limit.

The following references were used as the basis for identifying and defining the Available Control Technology or ACT shown in Tables 3-3-A through 3-3-L: References 1, 7, 8, 11, 12, 13, and 14.

TABLE 3-2. KEY TO TABLES 3-3-A THROUGH 3-3-L

Table No.	Rule Emission Limit and Category
3-3-A	300 ppm, Rule 474, (Los Angeles, Riverside, and San Bernardino Counties), Fuel Burning Equipment, 555 to <1786 10^6 Btu/hr (163 to <523 MW), Gaseous Fuel
3-3-B	400 ppm, Rule 474, (Los Angeles, Riverside, and San Bernardino Counties), Fuel Burning Equipment, 555 to <1786 10^6 Btu/hr (165 to <523 MW), Liquid Fuel
3-3-C	225 ppm, Rule 474, (Los Angeles, Riverside, and San Bernardino Counties), Fuel Burning Equipment, 1786 to <2143 10^6 Btu/hr (523 to <628 MW), Gaseous Fuel
3-3-D	325 ppm, Rule 474, (Los Angeles, Riverside, and San Bernardino Counties), Fuel Burning Equipment, 1786 to <2143 10^6 Btu/hr (523 to <628 MW), Liquid Fuel
3-3-E	125 ppm, Rule 474, (Los Angeles, Riverside, and San Bernardino Counties), Fuel Burning Equipment, ≥2143 10^6 Btu/hr (≥628 MW), Gaseous Fuel
3-3-F	225 ppm, Rule 474, (Los Angeles, Riverside, and San Bernardino Counties), Fuel Burning Equipment, ≥2143 10^6 Btu/hr (≥628 MW), Liquid Fuel
3-3-G	125 ppm, Rule 474, (Riverside, and San Bernardino Counties), Steam Generating Equipment, ≥555 10^6 Btu/hr (≥163 MW), Gaseous Fuel
3-3-H	225 ppm, Rule 474, (Riverside, and San Bernardino Counties), Steam Generating Equipment, ≥555 10^6 Btu/hr (≥163 MW), Liquid Fuel
3-3-I	225 ppm, Rule 68 Orange County, Fuel Burning Equipment, >500 to <2150 10^6 Btu/hr (≥147 to <630 MW), Gaseous Fuel
3-3-J	325 ppm, Rule 68 Orange County, Fuel Burning Equipment, >500 to <2150 10^6 Btu/hr (≥147 to <630 MW), Liquid Fuel
3-3-K	125 ppm, Rule 68 Orange County, Fuel Burning Equipment, ≥2150 10^6 Btu/hr (≥630 MW), Gaseous Fuel
3-3-L	225 ppm, Rule 68 Orange County, Fuel Burning Equipment, ≥2150 10^6 Btu/hr (≥630 MW), Liquid Fuel

TABLE 3-3-A. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning	555 to <1786 (163 to <523)	Gas Fuel 300	Utility Boiler	350-800	300-680 (Average reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							225-520 (Average reduction 35%)	Burners out of Service or Biased Burner Firing 1,2*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.
							175-400 (Average reduction 50%)	Overfire Air 1,2*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.

*1. * Signifies the control case technology that does not result in attainment of emission limit.
2. * Signifies the control case technology that is adequate to attain the emission limit.
3. * Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-A. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning	555 to <1786 (163 to <523)	Gas Fuel 300	Utility Boiler	350-800	175-400 (Average reduction 50%)	Reduced Load 1,2*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							175-400 (Average reduction 50%)	Flue Gas Recirculation 1,2*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							175-400 (Average reduction 50%)	Low NO_x Burners 1,2*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.
							100-150 (Average reduction 70%)	Combined Combustion Modifications Controls 3*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; (Continued)

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-A. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
									reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-B. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning	555 to <1786 (163 to <523)	Liquid Fuel, 400	Utility Boilers	350-500	300-400 (Average reduction 15%)	Low Excess Air 2*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							300-425 (Average reduction 15%)	Flue Gas Recirculation 2*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							250-350 (Average reduction 30%)	Burners out of Service or Biased Burner Firing 3*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-B. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning	555 to <1786 (163 to <523)	Liquid fuel, 400	Utility Boilers	350-500	250-350 (Average reduction 30%)	Overfire Air 3*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.
							250-350 (Average reduction 30%)	Reduced Load 3*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							225-300 (Average reduction 35%)	Low NO_x Burners 3*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-B. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	555 to <1786 (163 to <523)	Liquid Fuel, 400	Utility Boilers	350-500	200-250 (Average reduction 45%)	Combined Combustion Modifications Controls 3*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-C. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	1786 to <2143 (523 to <628)	Gas Fuel 225	Utility Boilers	350-800	300-680 (Average reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							225-520 (Average reduction 35%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.
							175-400 (Average reduction 50%)	Overfire Air 1,2*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-C. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	1786 to <2143 (523 to <628)	Gas Fuel 225	Utility Boilers	350-800	175-400 (Average reduction 50%)	Reduced Load 1,2*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							175-400 (Average reduction 50%)	Flue Gas Recirculation 1,2*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							175-400 (Average reduction 50%)	Low NO_x Burners 1,2*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.
							100-150 (Average reduction 75%)	Combined Combustion Modifications Controls 3*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load (Continued)

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-C. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
									plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-D. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_X STATIONARY SOURCE RETROFIT EMISSION LIMITS

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Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	1786 to <2143 (523 to <628)	Liquid Fuel 325	Utility Boilers	350-500	300-400 (Average reduction 15%)	Low Excess Air 1,2*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							300-425 (Average reduction 15%)	Flue Gas Recirculation 1,2*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							250-350 (Average reduction 30%)	Burners out of Service or Biased Burner Firing 2,3*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-D. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	1786 to <2143 (523 to <628)	Liquid Fuel 325	Utility Boilers	350-500	250-350 (Average reduction 30%)	Overfire Air 2,3*	A form of off-stoichiometric combustion 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.
							250-350 (Average reduction 30%)	Reduced Load 2,3*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							225-300 (Average reduction 35%)	Low NO_x Burners 3*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-D. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	1786 to <2143 (523 to <628)	Liquid Fuel 325	Utility Boilers	350-500	200-250 (Average reduction 45%)	Combined Combustion Modifications Controls 3*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-E. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	≥2143 (≥628)	Gas Fuel, 125	Utility Boilers	350-800	300-680 (Average reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature,cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							225-520 (Average reduction 35%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.
							175-400 (Average reduction 50%)	Overfire Air 1*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-E. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	$\geq$2143 ($\geq$628)	Gas Fuel, 125	Utility Boilers	350-800	175-400 (Average reduction 50%)	Reduced Load 1*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							175-400 (Average reduction 50%)	Flue Gas Recirculation 1*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be-derated.
							175-400 (Average reduction 50%	Low NO_x Burner 1*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.
							100-150 (Average reduction 75%)	Combined Combustion Modifications Controls 2*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; (Continued)

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-E. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	≥2143 (≥628)	Gas Fuel, 125	Utility Boilers	350-800			reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.
							60-90 (Average reduction 85%)	Noncatalytic Ammonia Injection plus Combined Combustion Modification Controls 3*	Ammonia injection requires detailed flue gas temperature mapping inside boiler before installation of injection grids; potential problems are NH_3 and HCN emissions and corrosive sulfate formation with oil firing; difficult process control required to assure NH_3 injected at desired flue gas temperature as boiler load varies; staggered injection grids or hydrogen injection may be required. Additional equipment to maintain and operate.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-E. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	$\gtrsim$2143 ($\gtrsim$628)	Gas Fuel, 125	Utility Boilers	350-800	10-15 (Average reduction 97%)	Selective Catalytic Reduction Using Ammonia Plus Combined Combustion Modification Controls 3*	Selective catalytic reduction has been used in Japan on a few commercial and many prototype units but it has not been used in the U.S. on a commercial basis. When burning sulfur containing fuels, catalyst fouling by SO_x could be a problem; if particulate matter is present, plugging or erosion of the catalyst is possible. Some of these problems can be remedied through the use of the optimized catalyst configuration or type of bed; ammonia carryover is possible which, besides NH_3 emissions, can lead to formation of ammonia bisulfate if SO_x is present; ammonia bisulfate can foul the air preheater and cause visible plumes. Additional equipment to maintain and operate; space limitations could cause retrofit difficulties.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-F. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_X STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A. Riverside, San Bernardino	Fuel Burning Equipment	≥ 2143 (≥ 628)	Liquid Fuel, 225	Utility Boilers	350-500	300-400 (Average reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							300-425 (Average reduction 15%)	Flue Gas Recirculation 1*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							250-350 (Average reduction 30%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-F. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	$\geq$2143 ($\geq$628)	Liquid Fuel, 225	Utility Boilers	350-500	250-350 (Average reduction 30%)	Overfire Air 1*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.
							250-350 (Average reduction 30%)	Reduced Load 1*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							225-300 (Average reduction 35%)	Low NO_x Burners 1*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-F. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A., Riverside, San Bernardino	Fuel Burning Equipment	$\geq$2143 ($\geq$628)	Liquid Fuel, 225	Utility Boilers	350-500	200-250 (Average reduction 45%)	Combined Combustion Modification Controls 2*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.
							120-150 (Average reduction 65%)	Noncatalytic ammonia Injection plus Combined Combustion Modification Controls 3*	Ammonia injection requires detailed flue gas temperature mapping inside boiler before installation of injection grids; potential problems are NH_3 and HCN emissions and corrosive sulfate formation with oil firing; difficult process control required to assure NH_3 injected at desired flue gas temperature as boiler load varies; staggered injection grids (Continued)

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-F. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	L.A. Riverside, San Bernardino	Fuel Burning Equipment	≥2143 (≥628)	Liquid Fuel, 225	Utility Boilers	350-500			or hydrogen injection may be required. Additional equipment to maintain and operate.
							20-25 (Average reduction 95%)	Selective Catalytic Reduction with Ammonia plus Combined Combustion Modification Controls 3*	Selective catalytic reduction has been used in Japan on a few commercial and many prototype units but it has not been used in the U.S. on a commercial basis. When burning sulfur containing fuels, catalyst fouling by SO_x could be a problem; if particulate matter is present, plugging or erosion of the catalyst is possible; some of these problems can be remedied through the use of the optimized catalyst configuration or type of bed; ammonia carryover is possible which, besides NH_3 emissions, can lead to formation of ammonia bisulfate if SO_x is present; ammonia bisulfate can foul the air preheater and cause visible plumes. Additional equipment to maintain and operate; space limitations could cause retrofit difficulties.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-G. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernardino	Steam Generating Equipment	$\geq$555 ($\geq$163)	Gas Fuel, 125	Utility Boilers	350-800	300-680 (Average reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							225-520 (Average reduction 35%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.
							175-400 (Average reduction 50%)	Overfire Air 1*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for (Continued)

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-G. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernardino	Steam Generating Equipment	≥555 (≥163)	Gas Fuel, 125	Utility Boilers	350-800			smoke and CO control; based on tests on opposed wall boilers.
							175-400 (Average reduction 50%)	Reduced Load 1*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							175-400 (Average reduction 50%)	Flue Gas Recirculation 1*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							175-400 (Average reduction 50%)	Low NO_x Burners 1*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.
							100-150 (Average reduction 70%)	Combined Combustion Modifications	The required combination of combustion modification controls to reach this emission level is very boiler dependent; (Continued)

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-G. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernardino	Steam Generating Equipment	≥ 555 (≥ 163)	Gas Fuel, 125	Utility Boilers	350-800		Control 2*	some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.
							60-90 (Average reduction 85%)	Noncatalytic Ammonia Injection plus Combined Combustion Modification Controls 3*	Ammonia injection requires detailed flue gas temperature mapping inside boiler before installation of injection grids; potential problems are NH_3 and HCN emissions and corrosive sulfate formation with oil firing; difficult process control required to assure NH_3 injected at desired flue gas temperature as boiler load varies; staggered injection grids or hydrogen injection may be required. Additional equipment to maintain and operate.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-G. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernardino	Steam Generating Equipment	$\geq$555 ($\geq$163)	Gas Fuel, 125	Utility Boilers	350-800	10-15 (Average reduction 97%)	Selective Catalytic Reduction Using Ammonia Plus Combined Combustion Modification Controls 3*	Selective catalytic reduction has been used in Japan on a few commercial and many prototype units but it has not been used in the U.S. on a commercial basis. When burning sulfur containing fuels, catalyst fouling by SO_x could be a problem; if particulate matter is present, plugging or erosion of the catalyst is possible; some of these problems can be remedied through the use of the optimized catalyst configuration or type of bed; ammonia carryover is possible which, besides NH_3 emissions, can lead to formation of ammonia bisulfate if SO_x is present; ammonia bisulfate can foul the air preheater and cause visible plumes. Additional equipment to maintain and operate; space limitations could cause retrofit difficulties.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-H. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_X STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernadino	Steam Generating Equipment	$\geq$ 555 ($\geq$163)	Liquid Fuel, 225	Utility Boilers	350-500	300-400 (Average reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							300-425 (Average reduction 15%)	Flue Gas Recirculation 1*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; may require boiler derate.
							250-350 (Average reduction 30%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-H. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernardino	Steam Generating Equipment	≥555 (≥163)	Liquid Fuel, 225	Utility Boilers	350-500	250-350 (Average reduction 30%)	Overfire Air 1*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.
							250-350 (Average reduction 30%)	Reduced Load 1*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							225-300 (Average reduction 35%)	Low NO_x Burners 1*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-H. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernardino	Steam Generating Equipment	$\geq$555 ($\geq$163)	Liquid Fuel, 225	Utility Boilers	350-500	200-250 (Average reduction 45%)	Combined Combustion Modification Controls 2*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.
							120-150 (Average reduction 65%)	Noncatalytic Ammonia Injection plus Combined Combustion Modification	Ammonia injection requires detailed flue gas temperature mapping inside boiler before installation of injection grids; potential problems are NH_3 and HCN emissions and corrosive sulfate formation with oil firing; difficult process control required to assure NH_3 injected at desired flue gas temperature as boiler (Continued)

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-H. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
474	Riverside, San Bernardino	Steam Generating Equipment	≥555 (≥163)		Liquid Fuel, 225	Utility Boilers	350-500	Controls 3*	load varies; staggered injection grids or hydrogen injection may be required. Additional equipment to maintain and operate.
							20-25 (Average reduction 95%)	Selective Catalytic Reduction with Ammonia plus Combined Combustion Modification Controls 3*	Selective catalytic reduction has been used in Japan on a few commercial and many prototype units but it has not been used in the U.S. on a commercial basis. When burning sulfur containing fuels, catalyst fouling by SO_x could be a problem; if particulate matter is present, plugging or erosion of the catalyst is possible; some of these problems can be remedied through the use of the optimized catalyst configuration or type of bed; ammonia carryover is possible which, besides NH_3 emissions, can lead to formation of ammonia bisulfate if SO_x is present; ammonia bisulfate can foul the air preheater and cause visible plumes. Additional equipment to maintain and operate; space limitations could cause retrofit difficulties.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-I. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	>500 to >2150 (>147 to >630)	Gas Fuel, 225	Utility Boilers	350-800	300-680 (Average reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							225-520 (Average reduction 35%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.
							175-400 (Average reduction 50%)	Overfire Air 1,2*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-I. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	>500 to <2150 (>147 to <630)	Gas Fuel, 225	Utility Boilers	350-800	175-400 (Average reduction 50%)	Reduced Load 1,2*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							175-400 (Average reduction 50%)	Flue Gas Recirculation 1,2*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							175-400 (Average reduction 50%)	Low NO_x Burners 1,2*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.
							100-150 (Average reduction 70%)	Combined Combustion Modifications Controls 3*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged (Continued)

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-I. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	>500 to <2150 (>147 to <630)	Gas Fuel, 225	Utility Boilers	350-800			combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

a. Some boilers are outside this range.

b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-J. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_X STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	>500 to <2150 (>147 to <630)	Liquid Fuel 325	Utility Boilers	350-500	300-400 (Average Reduction 15%)	Low excess air 1,2*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature,cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							300-425 (Average Reduction 15%)	Flue Gas Recirculation 1,2*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							250-350 (Average Reduction 30%)	Burners out of Service or Biased Burner Firing 2,3*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-J. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	>500 to <2150 (>147 to <630)	Liquid Fuel 325	Utility Boilers	350-500	250-350 (Average Reduction 30%)	Overfire Air 2,3*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.
							250-350 (Average Reduction 30%)	Reduced Load 2,3*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							225-300 (Average Reduction 35%)	Low NO_x Burners 3*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-J. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	>500 to <2150 (>147 to <630)	Liquid Fuel 325	Utility Boilers	350-500	200-250 (Average Reduction 45%)	Combined Combustion Modifications Controls 3*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

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TABLE 3-3-K. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_X STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Gas Fuel, 125	Utility Boilers	350-800	300-680 (Average Reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature, cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							225-520 (Average Reduction 35%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.
							175-400 (Average Reduction 50%)	Overfire Air 1*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.

a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-K. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Gas Fuel, 125	Utility Boilers	350-800	175-400 (Average Reduction 50%)	Reduced Load 1*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							175-400 (Average Reduction 50%)	Flue Gas Recirculation 1*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							175-400 (Average Reduction 50%)	Low NO_x Burner 1*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.
							100-150 (Average Reduction 70%)	Combined Combustion Modifications Controls 2*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load (Continued)

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-K. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Gas Fuel, 125	Utility Boilers	350-800			plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.
							60-90 (Average Reduction 85%)	Noncatalytic Ammonia Injection plus Combined Combustion Modification Controls 3*	Ammonia injection requires detailed flue gas temperature mapping inside boiler before installation of injection grids; potential problems are NH_3 and HCN emissions and corrosive sulfate formation with oil firing; difficult process control required to assure NH_3 injected at desired flue gas temperature as boiler load varies; staggered injection grids or hydrogen injection may be required. Additional equipment to maintain and operate.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-K. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Gas Fuel 125	Utility Boilers	350-800	10-15 (Average Reduction 97%)	Selective Catalytic Reduction Using Ammonia Plus Combined Combustion Modification Controls 3*	Selective catalytic reduction has been used in Japan on a few commercial and many prototype units but it has not been used in the U.S. on a commercial basis. When burning sulfur containing fuels, catalyst fouling by SO_x could be a problem. If particulate matter is present, plugging or erosion of the catalyst is possible; some of these problems can be remedied through the use of the optimized catalyst configuration or type of bed; ammonia carryover is possible which, besides NH_3 emissions, can lead to formation of ammonia bisulfate if SO_x is present; ammonia bisulfate can foul the air preheater and cause visible plumes. Additional equipment to maintain and operate; space limitations could cause retrofit difficulties.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-L. AVAILABLE CONTROL TECHNOLOGY RELATED TO SIP NO_X STATIONARY SOURCE RETROFIT EMISSION LIMITS

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Liquid Fuel, 225	Utility Boilers	350-500	300-400 (Average Reduction 15%)	Low excess air 1*	Can increase thermal efficiency of boiler; better flue gas monitoring required; if excess air used to control steam temperature,cycle efficiency can drop; excess air reduction is limited by increases in smoke and CO.
							300-425 (Average Reduction 25%)	Flue Gas Recirculation 1*	Increased fan power; limited by flame stability problems; may require windbox and burner modifications; boiler may need to be derated.
							250-350 (Average Reduction 30%)	Burners out of Service or Biased Burner Firing 1*	A form of off-stoichiometric combustion or 2-stage combustion; better flue gas monitoring required; limited by CO build up; possible flame stability problems; could require boiler derate; burner modifications may be needed, more fan power may be required, thermal efficiency may decrease.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-L. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Liquid Fuel, 225	Utility Boilers	350-500	250-350 (Average Reduction 30%)	Overfire Air 1*	A form of off-stoichiometric combustion or 2-stage combustion; overfire air ports need to be retrofitted; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air used for smoke and CO control; based on tests on opposed wall boilers.
							250-350 (Average Reduction 30%)	Reduced Load 1*	Excess boiler capacity required; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; very wide NO_x reduction range reported.
							225-300 (Average Reduction 35%)	Low NO_x Burners 1*	Burners have been tested in Japan but not in the U.S.; because of flame shape, may not be able to retrofit in all boilers.

*1. ~ Signifies the control case technology that does not result in attainment of emission limit.
2. ~ Signifies the control case technology that is adequate to attain the emission limit.
3. ~ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-L. Continued

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Liquid Fuel, 225	Utility Boilers	350-500	200-250 (Average Reduction 45%)	Combined Combustion Modification Controls 2*	The required combination of combustion modification controls to reach this emission level is very boiler dependent; some combinations used are low excess air plus 2-stage combustion; staged combustion plus flue gas recirculation; reduced load plus staged combustion; reduced load plus staged combustion plus flue gas recirculation. Further reduction could be achieved by the use of noncatalytic ammonia injection or catalytic ammonia injection. In all cases, low excess air should be used if possible to increase thermal efficiency.
							120-150 (Average Reduction 65%)	Noncatalytic Ammonia Injection plus Combined Combustion Modification Controls 3*	Ammonia injection requires detailed flue gas temperature mapping inside boiler before installation of injection grids; potential problems are NH_3 and HCN emissions and corrosive sulfate formation with oil firing; difficult process control required to assure NH_3 injected (Continued)

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.
a. Some boilers are outside this range.
b. In some applications, emissions levels less than those listed below can be achieved.

TABLE 3-3-L. Concluded

Rule	Affected Area	Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emission Limit: ppm NO_x dry, at 3% O_2, 15 min. avg., by fuel type	Subcategory	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
						Base[a]	Controlled[b]		
68	Orange Co.	Fuel Burning Equipment	≥2150 (≥630)	Liquid Fuel, 225	Utility Boilers	350-500	(Continued from previous page)		at desired flue gas temperature as boiler load varies; staggered injection grids or hydrogen injection may be required. Additional equipment to maintain and operate.
							20-25 (Average Reduction 95%)	Selective Catalytic Reduction with Ammonia plus Combined Combustion Modification Controls 3*	Selective catalytic reduction has been used in Japan on a few commercial and many prototype units but it has not been used in the U.S. on a commercial basis. When burning sulfur containing fuels, catalyst fouling by SO_x could be a problem; if particulate matter is present, plugging or erosion of the catalyst is possible; some of these problems can be remedied through the use of the optimized catalyst configuration or type of bed; ammonia carryover is possible, which besides NH_3 emissions, can lead to formation of ammonia bisulfate if SO_x is present; ammonia bisulfate can foul the air preheater and cause visible plumes. Additional equipment to maintain and operate; space limitations could cause retrofit difficulties.

*1. ∿ Signifies the control case technology that does not result in attainment of emission limit.
2. ∿ Signifies the control case technology that is adequate to attain the emission limit.
3. ∿ Signifies the control case technology that exceeds emission limit requirements.

[a] Some boilers are outside this range.

[b] In some applications, emissions levels less than those listed below can be achieved.

3.3 NO_x AVAILABLE CONTROL TECHNOLOGY RELATED TO SCAQMD SOURCES NOT AFFECTED BY SIP RETROFIT RULE EMISSION LIMITS

Tables 3-5 through 3-10 present data and analysis related to the application of ACT to NO_x stationary emissions sources that are not affected by the present SIP NO_x retrofit control rules in the SCAQMD.

The 1979 SIP revisions for the SCAQMD area that were recently submitted to EPA contain a number of recommended stationary source NO_x retrofit emission control measures. Control measures are recommended in the SIP for almost all of the source categories for which ACT is identified in this section (see Table 3-4 for a list of ACT control measures identified in this section). Those stationary source categories, for which ACT NO_x control measures are available and for which control measures are also recommended in the SIP revisions, are as follows:

- Process refinery heaters (and boilers)
- Industrial boilers
- Stationary internal combustion engines
- Glass melting furnaces
- Cement kilns

ACT is identified in this study for certain gas turbine categories. The SCAQMD SIP revisions do not contain a recommendation to control gas turbines that are presently uncontrolled, although such controls are considered and discussed in the SIP revisions submittal. The SIP revisions do contain a recommendation for NO_x retrofit controls for medium and small steam generators used to provide power for locally consumed electricity (i.e., utility boilers). While ACT for such sources is not defined in this study, the relationship of ACT to this source category is discussed in the following paragraph.

ACT is not identified for smaller uncontrolled utility boilers (i.e., utility boilers less than 500×10^6 Btu/hr capacity) because control data for such sources is not available. However, it appears that the ACT identified for "residual oil watertube" and "natural gas watertube with air preheater" industrial boilers which is discussed in Tables 3-7-D and 3-7-H presents at least an approximation of ACT that could be applicable to smaller utility boilers having similar capacity and emissions base level NO_x concentrations. The available data on such smaller utility boilers shows that the range of emissions base level NO_x concentrations are similar to those reported for the two types of industrial boilers as reported in these two tables. Also, ACT is not identified for CO boilers in oil refineries. It may be possible to control these units by using the same controls as identified for industrial and utility boilers, but tests are needed to confirm this.

The San Diego SIP NO_x stationary source retrofit control rule affects virtually all of the areas fuel burning sources that have a maximum heat input greater than 50 x 10^6 Btu/hr (15 MW) and essentially requires the application of ACT. However, many source categories that fall into this control range are not found in the San Diego area (e.g., petroleum process heaters, cement kilns and glass furnaces) but are found in the SCAQMD area and are discussed in Tables 3-5 through 3-10. Some source categories discussed in these tables have maximum heat input capacities less than 50 x 10^6 Btu/hr (e.g., some industrial boilers and stationary internal combustion engines) and may be found in the San Diego area as well as the SCAQMD area. Such smaller sources could be considered as candidates for the application of retrofit controls in the San Diego area as well as the SCAQMD area.

Following is a discussion of the information presented in Table 3-5 through 3-10:

- The first two columns in the tables describe the equipment "category" and the energy input or "capacity" of the equipment for which NO_x control technology data are presented in later columns
- The tables are subdivided by general source category (i.e., Table 3-5 for "gas turbines" and Table 3-6 for "process refinery heaters", etc.). Each general source category is then further subdivided in the category column of the table (e.g., "gas turbine oil-fired", "gas turbine gas-fired"). The general source category for industrial boilers contains a very large variety of boiler types; and for this category, a table is presented for each boiler type. See Table 3-4 "Key to Tables 3-5 through 3-10" just preceding these tables.

- The "Emissions" columns describe the emissions range for the "Base" case (i.e., uncontrolled) levels and for the "Controlled" case. The "Controlled" case identifies the emissions range associated with the ACT described in the "Available Control Technology" column. The average ppm concentration reduction expressed in percent is also shown in the "Emissions: Controlled" column. The reported percent concentration reduction is average in that it is the reduction from the base case that can be expected by application of the ACT on the average combustion equipment being discussed.
- Comments describing the ACT application limitations and qualifications are found in the "Application Comments" column
- The reader should be alert to the fact that the emissions levels shown in the "Emissions Base" and "Emissions Controlled" columns are measured at steady state operating condition, while the emission limits expressed in the SIP NO_x control rules are 15 minute averages. It is possible that such a 15 minute average emission limit could be exceeded by the controlled equipment during start-up or during load fluctuation periods, even though the steady state emission level would not exceed the rule 15 minute average emission limit value.

The following references were used as the basis for identifying and defining the available control technology or ACT shown in Tables 3-5 through 3-10: References 8, 11, 12, 13, 14, 15, 16, 28, 29, 30, 31, 32, 33, 34, 35, 36 and 39.

TABLE 3-4. KEY TO TABLES 3-5 THROUGH 3-10

Table Number	Source Category Discussed
3-5	Gas Turbines
3-6	Process Refinery Heaters
	Industrial Boilers:
3-7-A	Residual Oil Firetube
3-7-B	Distillate Oil Firetube
3-7-C	Natural Gas Firetube
3-7-D	Residual Oil Watertube
3-7-E	Distillate Oil Watertube without Air Preheater
3-7-F	Distillate Oil Watertube with Air Preheater
3-7-G	Natural Gas Watertube without Air Preheater
3-7-H	Natural Gas Watertube with Air Preheater
	Stationary Internal Combustion Engines:
3-8-A	Natural Gas
3-8-B	Diesel
3-8-C	Dual Fuel
3-9	Glass Melting Furnaces
3-10	Cement Kilns

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TABLE 3-5. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

GAS TURBINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Gas turbines, oil fired, utility	>100 (>29)	300-600	150-300 (Average reduction 50%)	Water injection or steam injection	Water must be very clean; extra equipment to maintain; thermal efficiency decrease; power output gain; possible CO, HC emission increase; some water pollution from regeneration of water purification system; this control technique being used by utilities.
Gas turbines, gas fired, utility	>100 (>29)	300-400	150-200 (Average reduction 50%)	Water injection or steam injection	Same comments as for oil fired gas turbine; this control technique being used by utilities.

a. Some equipment are outside this range

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-5. Concluded

GAS TURBINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Gas turbines, oil fired	<100 (<29)	300-600	150-300 (Average reduction 50%)	Water injection or steam injection	Same comments as for utility-sized turbines but there have been fewer tests on these smaller turbines; availability based on short term tests.
Gas turbines, gas fired	<100 (<29)	300-400	150-200 (Average reduction 50%)	Water injection or steam injection	Same comments as for the utility-sized turbines but there have been fewer tests on these smaller turbines; availability based on short term tests.

[a] Some equipment are outside this range.

[b] In some applications, emissions levels less than those listed can be achieved.

TABLE 3-6. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

PROCESS REFINERY HEATERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Natural draft process heaters, Refinery gas-fired	16-394 (5-115)	60-195	54-175 (Average reduction 10%)	Burners out of service	Generally results in increased excess air limit; thermal efficiency drops; fuel flow used as an aid to induce combustion air and this suppresses the degree of staged combustion; availability based on short term tests
			48-135 (Average reduction 25%)	Load Variation	As load increases, NO_x levels decrease; excess air reduced as load increases; slight increase in thermal efficiency; availability based on only two short term tests.
			52-170 (Average reduction 15%)	Air register adjustment	CO levels unaffected; no significant effect on thermal efficiency; availability based on only 3 short term tests.
			35-100 (Average reduction 45%)	Noncatalytic Ammonia Injection plus Combustion Modification Controls	Based on one Japanese test; requires detailed flue gas temperature mapping inside heater before installation of injection grids; potential problems are NH_3, HCN emissions and corrosive sulfate formation with sulfur containing fuels; difficult process control required to assure NH_3 injected at desired flue gas temperature as heater load varies. Additional equipment to maintain and operate.

a. Some equipment are outside this range.
b. In some applications, emission levels less than those listed can be achieved.

TABLE 3-6. Continued

PROCESS REFINERY HEATERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Mechanical draft process heaters, Refinery gas-fired	35-105 (10-31)	215	70-138 (Average reduction 50%)	Low excess air and load reduction	Slight improvement in thermal efficiency. CO levels unaffected. Baseline at 45% load. Small load reduction to 36% during test. Availability based on one short term test.
Mechanical draft process heaters, Refinery gas & residual oil fired	35-105 (10-31)	170	145-165 (Average reduction 10%)	Low excess air	Chance of loss in thermal efficiency; CO levels unaffected; may have been small load reduction during test; availability based on one short term test.
Mechanical draft process heaters, Refinery gas or refinery gas & residual oil fired	35-105 (10-31)	170-215	100-130 (Average reduction 40%)	Noncatalytic Ammonia Injection plus Combustion Modification Controls	Based on one Japanese test; Requires detailed flue gas temperature mapping inside heater before installation of injection grids; potential problems are NH_3, HCN emissions and corrosive sulfate formation with S containing fuels; difficult process control required to assure NH_3 injected at desired flue gas temperature as heater load varies; Additional equipment to maintain and operate.

a. Some equipment are outside this range.
b. In some applications, emission levels less than those listed can be achieved.

TABLE 3-6. Concluded

PROCESS REFINERY HEATERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Mechanical draft process heaters, Refinery gas or refinery gas and residual oil fired	35-105 (10-31)	170-215	20-25 (Average reduction 90%)	Selective Catalytic Reduction using ammonia plus combustion modification controls	Selective catalytic reduction used in Japan on one unit but not in the U.S.; sulfur containing fuels can foul catalyst; particulate matter can cause plugging or erosion of catalyst; NH_3 carryover possible and with SO_x can lead to visible plumes and to corrosion of an air preheater; on small sources, retrofitting can be limited by space requirement of flue gas heater; additional equipto maintain and operate.

a. Some equipment are outside this range.
b. In some applications, emission levels less than those listed can be achieved.

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TABLE 3-7-A. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: residual oil firetube	5-30 (1-9)	170-300	150-280 (Average reduction 5%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels. Availability based on short term tests.
			155-285 (Average reduction 5%)	Reduced load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability which may lead to increased NO_x levels; may decrease thermal efficiency; availability based on few short term tests.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-A. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: residual oil firetube	5-30 (1-9)	170-300	135-235 (Average reduction 20%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability; may decrease thermal efficiency; availability based on small number of short term tests; could be difficult to retrofit.
			110-195 (Average reduction 35%)	Staged combustion air	Overfire or side fire air ports need to be retrofitted and could be very difficult; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air is used for smoke & CO control; availability based on few short term tests; could limit fuel switching ability.
			100-130 (Average reduction 40%)	Low NO_x burners	Burners have been tested in Japan but limited testing the U.S.; because of modified flame shape, may not be able to retrofit in all boilers.

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a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-B. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil firetube	5-30 (1-9)	170-190	150-170 (Average reduction 10%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels; availability based on few short term tests.
			155-170 (Average reduction 10%)	Reduced load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability which may lead to increased NO_x levels; may decrease thermal efficiency; availability based on few short term tests.
			100-110 (Average reduction 40%)	Low NO_x burners	Burners have been tested in Japan but limited testing in the U.S.; because of modified flame shape, may not be able to retrofit in all boilers.
			120-135 (Average reduction 30%)	Staged Combustion air	Overfire or side fire air ports need to be retrofitted & could be very difficult; more fan power may be required; limited by smoke & CO formation; thermal efficiency will drop if higher excess air is used for smoke & CO control; availability based on few short term tests; could limit fuel switching ability

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-B. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil firetube	5-30 (1-9)	170-190	85-95 (Average reduction 50%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; availability based on small number of short term tests; difficult retrofit due to site specific space limitations and hardware constraints.

a. Some equipment are outside this range

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-C. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas firetube	5-30 (1-9)	55-110	50-100 (Average reduction 10%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels; availability based on short term tests.

a. Some equipment are outside this range.

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-C. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas firetube	5-30 (1-9)	55-110	50-100 (Average reduction 10%)	Reduced load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability which may lead to increased NO_x levels; may decrease thermal efficiency; availability based on short term tests.
			40-85 (Average reduction 25%)	Staged combustion air	Side fire air ports need to be retrofitted and could be difficult; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air is used for smoke and CO control; availability based on few short term tests.
			25-55 (Average reduction 50%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability; may decrease thermal efficiency; availability based on few short term tests; difficult retrofit.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-D. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: residual oil watertube	15-300 (4-88)	120-400	105-350 (Average reduction 15%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels; availability based on few short term tests.
			95-320 (Average reduction 20%)	Burners out of service	Better flue gas monitoring required; limited by CO build up; possible flame stability problems; could derate boiler; boiler modifications may be needed; more fan power may be required; thermal efficiency may decrease; applicable for multiburner units; availability based on short term tests.
			110-360 (Average reduction 10%)	Reduced load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability which may lead to increased NO_x levels; may decrease thermal efficiency; availability based on few short term tests.

a. Some equipment are outside this range.

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-D. Continued

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers; residual oil watertube	15-300 (4-88)	120-400	95-310 (Average reduction 20%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability; may decrease thermal efficiency; availability based on few short term tests; could be difficult retrofit.
			70-250 (Average reduction 40%)	Low NO_x Burners	Burners have been tested in Japan but limited testing in the U.S.; because of flame shape may not be able to retrofit in all boilers.
			75-245 (Average reduction 40%)	Combination Combustion Modification Controls	The required combination of combustion modification controls to reach this emission level is very boiler dependent. Flue gas recirculation plus overfire air has been tested; in all cases low excess air should be used if possible to increase thermal efficiency; availability based on few short term tests; could be difficult retrofit.
			80-260 (Average reduction 35%)	Staged Combustion Air	Overfire air ports need to be retrofitted and could be difficult to retrofit; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air is used for smoke and CO control. Availability based on few short term tests.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-D. Continued

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: residual oil watertube	15-300 (4-88)	120-400	45-150 (Average reduction 65%)	Non-catalytic ammonia injection plus combustion modification controls	Ammonia injection requires flue gas temperature mapping before installation of injecting grids; potential problems are NH_3, HCN emissions and corrosive sulfate formation; difficult process control to follow load variations, could even require H_2 injection; additional equipment to maintain and operate; commercial application limited to Japan primarily for larger sized units; one short term test in the U.S.; because of narrow temperature window may not be applicable to all boilers.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-D. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: residual oil watertube	15-300 (4-88)	120-400	10-30 (Average reduction 90%)	Selective catalytic reduction using ammonia plus combustion modification controls	Selective catalytic reduction used in Japan on a few units but not in the U.S.; sulfur containing fuels can foul catalyst; particulate matter can cause plugging or erosion of catalyst; NH_3 carryover possible and with SO_x can lead to visible plumes and to corrosion of an air preheater. On small sources, retrofitting can be limited by space requirement and may require a flue gas heater; additional equipment to maintain and operate; may require additional fan capacity.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-E. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil watertube without air preheater	15-150 (4-44)	80-110	70-95 (Average reduction 15%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels. Availability based on short term tests.
			70-100 (Average reduction 10%)	Reduced load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability which may lead to increased NO_x levels; may decrease thermal efficiency; availability based on short term tests.

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a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-E. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil watertube without air preheater	15-150 (4-44)	80-110	45-65 (Average reduction 40%)	Low NO_x burners	Burners have been tested in Japan but limited testing in the U.S.; because of flame shape may not be able to retrofit in all boilers.
			55-80 (Average reduction 30%)	Staged combustion air	Overfire air ports need to be retrofitted & could be difficult; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air is used for smoke and CO control; availability based on few short term tests.
			40-55 (Average reduction 50%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability; may decrease thermal efficiency; availability based on a few short term tests; could be difficult to retrofit.
			30-45 (Average reduction 60%)	Combination combustion modifications controls	The required combination of combustion modification controls to reach this emission level is very boiler dependent; flue gas recirculation plus overfire has been tested; in all cases, low excess air should be used if possible to increase thermal efficiency; could be difficult retrofits; availability based on few short term tests.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-F. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil watertube with air preheater	50-300 (15-88)	120-180	105-160 (Average reduction 10%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels; availability based on short term tests.
			110-160 (Average reduction 10%)	Reduced load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability and to control steam temperature which may lead to increased NO_x levels; may decrease thermal efficiency; availability based on short term tests.
			110-160 (Average reduction 10%)	Reduce air preheat	Large loss in thermal efficiency; availability based on short term testing of small number of units.
			85-125 (Average reduction 30%)	Staged combustion air	Overfire air ports need to be retrofitted and could be difficult; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air is used for smoke and CO control; availability based on few short term tests.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-F. Continued

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil watertube with air pre-heater	50-300 (15-88)	120-180	85-125 (Average reduction 30%)	Low NO_x burners	Burners have been tested in Japan but limited testing in the U.S.; because of flame shape may not be able to retrofit in all boilers.
			60-90 (Average reduction 50%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; availability based on small number of short term tests; could be difficult to retrofit.
			40-70 (Average reduction 60%)	Combination combustion modifications controls	The required combination of combustion modification controls to reach this emission level is very boiler dependent; flue gas recirculation plus overfire air has been tested; in all cases, low excess air should be used if possible to increase thermal efficiency; could be difficult retrofit; availability based on few short term tests.

[a] Some equipment are outside this range.
[b] In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-F. Continued

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil watertube with air preheater	50-300 (15-88)	120-180	15-25 (Average reduction 85%)	Selective catalytic reduction using ammonia	Selective catalytic reduction used in Japan on a small number of units but not in the U.S.; sulfur containing fuels can foul catalyst; particulate matter can cause plugging or erosion of catalyst; NH_3 carryover possible and with SO_x can lead to visible plumes and to corrosion of air preheater. On small sources, retrofitting can be limited by space requirement; additional equipment to maintain and operate; may require addition of induced draft fan.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-F. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: distillate oil watertube with air pre-heater	50-300 (15-88)	120-180	50-70 (Average reduction 60%)	Noncatalytic Ammonia injection plus combustion modification controls	Ammonia injection requires flue gas temperature mapping before installation of injection grids; potential problems are NH_3, HCN emissions. Difficult process control to follow load variations; could even require H_2 injection; additional equipment to maintain and operate; commercial application limited to Japan primarily for larger-sized units; because of narrow temperature window, may not be applicable to all boilers.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-G. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas watertube without air preheater	15-150 (4-44)	60-190	55-170 (Average reduction 10%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels; availability based on short term tests
			55-170 (Average reduction 10%)	Reduce load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability and to control steam temperature which may lead to increased NO_x levels; may decrease thermal efficiency; availability based on short term tests.
			45-145 (Average reduction 25%)	Staged combustion air	Overfire air ports need to be retrofitted and could be difficult; limited by smoke and CO formation; thermal efficiency will drop if higher excess air is used for smoke and CO control; availability based on small number of short term tests.

[a] Some equipment are outside this range.
[b] In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-G. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas watertube without air preheater	15-50 (4-15)	60-190	30-95 (Average reduction 50%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency; availability based on few short term tests; could be difficult to retrofit.
			25-75 (Average reduction 60%)	Combined combustion modification controls	The required combination of combustion modification controls to reach this emission level is very boiler dependent; flue gas recirculation plus overfire air was only combination tested; low excess air should be used if possible to increase thermal efficiency; could be difficult retrofit; availability based on small number of short term tests.
			35-115 (Average reduction 40%)	Low NO_x burners	Burners have been tested in Japan but limited testing in U.S.; because of flame shape may not be able to retrofit in all boilers.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-H. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas watertube with air preheater	50-300 (15-88)	95-370	85-330 (Average reduction 10%)	Low excess air	Can increase thermal efficiency of boiler; better flue gas monitoring required; low excess air limited by increase in smoke and CO levels. Based on short term tests.
			85-330 (Average reduction 10%)	Reduced load	Excess boiler capacity may be required; higher excess air levels may be required to maintain flame stability and to control steam temperature which may lead to increased NO_x levels; may decrease thermal efficiency. Based on short term tests.
			85-330 (Average reduction 10%)	Reduced air preheat	Large loss in thermal efficiency; availability based on short term testing of small number of units.
			65-260 (Average reduction 30%)	Burners out of services	Better flue gas monitoring required; limited by CO build up; possible flame stability problems; could derate boilers; boiler modifications may be needed; more fan power may be required; thermal efficiency may decrease; applicable for multiburner units only, based on small number of short term tests.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-H. Continued

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas watertube with air preheater	50-300 (15-88)	95-370	70-275 (Average reduction 25%)	Staged Combustion Air	Overfire air ports need to be retrofitted and could be difficult; more fan power may be required; limited by smoke and CO formation; thermal efficiency will drop if higher excess air is used for smoke and CO control. Based on a few short term tests.
			60-200 (Average reduction 40%)	Low NO_x burners	Burners have been tested in Japan but limited testing in the U.S.; because of flame shape may not be able to retrofit in all boilers
			50-185 (Average reduction 50%)	Flue gas recirculation	Increased fan power; higher excess air levels may be required to maintain flame stability and to control steam temperature; may decrease thermal efficiency. Based on a few short term tests. Could be difficult retrofit.
			40-150 (Average reduction 60%)	Combined combustion modifications controls	The required combination of combustion modification controls to reach this emission level is very boiler dependent; flue gas recirculation plus over fire air has been tested; further reduction could be achieved by the use of ammonia injection. In all

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-H. Continued

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas watertube with air preheater	50-300 (15-88)	95-370	40-150 (Average reduction 60%)	Combined combustion modifications controls	cases low excess air should be used if possible to increase thermal efficiency; could be difficult retrofit; based on small number of short term tests.
			40-150 (Average reduction 60%)	Noncatalytic ammonia injection plus combustion modification controls	Ammonia injection requires flue gas temperature mapping before installation of injection grids; potential problems are NH_3 and HCN emissions. Switching from gas to oil could be difficult because of injection grid location and formation of corrosive sulfur compounds. Difficult process control to follow load variations, could even require H_2 injection; additional equipment to maintain and operate; commercial application limited to Japan primarily for larger sized units; because of narrow temperature window may not be applicable to all boilers

a. Some equipment are outside this range

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-7-H. Concluded

INDUSTRIAL BOILERS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Industrial boilers: natural gas watertube with air preheater	50-300 (15-88)	95-370	10-40 (Average reduction 90%)	Selective catalytic reduction using ammonia	Selective catalytic reduction used in Japan on a small number of units but not in the U.S.; switching from gas to oil could be difficult because sulfur containing fuels can foul catalyst; particulate matter can cause plugging or erosion of catalyst; NH_3 carry over possible and with SO_x can lead to visible plumes and to corrosion of an air preheater. On small sources, retrofitting can be limited by space requirement; additional equipment to maintain and operate; may require addition of induced draft fan.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-8-A. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Stationary spark ignition internal combustion engines - natural gas fired	3.5 - ~50 (1-~15)	2000 - 5500	1600 - 4400 (Average reduction 20%)	Retard	Fuel consumption increase 1 to 4%; possible deterioration of exhaust valves and exhaust system; requires increased maintenance; limitation due to misfiring; technology demonstrated but not in use; possible CO, HC increases.
			1600 - 4400 (Average reduction 20%)	Manifold air cooling	Increase in HC and CO emissions; ambient temperatures limit maximum reduction; technology demonstrated but not in use; increased maintenance of cooling system; applicable to turbocharge engines only; could be retrofit problems.

a. Some equipment are outside this range.

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-8-A. Continued

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Stationary spark ignition internal comubstion engines - natural gas fired	3.5 - ∿ 50 (1-∿15)	2000 - 5500	1600 - 4400 (Average reduction 20%)	External exhaust gas recirculation	Increased maintenance of recirculation system and air intake system; CO emissions; technology demonstrated but not in use; could be retrofit problems.
			1600 - 4400 (Average reduction 20%)	Derate	Increase in fuel consumption 2 to 6%; need extra engine capacity; technology demonstrated but not in use.

a. Some equipment are outside this range.

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-8-A. Concluded

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Stationary spark ignition internal combustion engines - natural gas fired	3.5 - $\sim$ 50 (1-$\sim$15)	2000 - 5500	1400 - 3850 (Average reduction 30%)	Air to fuel change	Up to 5% increase in fuel consumption possible; increased maintenance; limited by misfiring; technology demonstrated but not in use; best for turbocharged, fuel-injected engine; increases in HC and possible CO increases.
			1200 - 3300 (Average reduction 40%)	Retard and manifold air cooling and air to fuel change	Increase in fuel consumption up to 7%; increased maintenance; increase in HC and CO emissions; technology demonstrated but not in use; could be retrofit problems.

a. Some equipment are outside this range.
b. In some applications, emission levels less than those listed can be achieved.

TABLE 3-8-B. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	**Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions**		**Available Control Technology**	**Application Comments**
		Base[a]	**Controlled**[b]		
Stationary compression ignition internal combustion engines -- oil-fired (diesel)	3.5 - ∿ 50 (1-∿15)	1150 - 3900	950 - 3100 (Average reduction 20%)	External exhaust gas recirculation	CO smoke levels increase; accumulation of solid exhaust products in the exhaust gas recirculation system affects durability and requires higher maintenance; technology demonstrated but not in use; could be retrofit problems.
			950 - 3100 (Average reduction 20%)	Derate	Increase in fuel consumption to 5%; extra engine capacity required; technology demonstrated but not in use.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-8-B. Continued

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Stationary compression ignition internal combustion engines -- oil-fired (diesel)	3.5 - ∿ 50 (1-∿15)	1150 - 3900	950 - 3100 (Average reduction 20%)	Retard and manifold air cooling	Fuel consumption increase of 1 percent; may require increased maintenance; CO and HC emissions increase; technology demonstrated but not in use; could be retrofit problems.
			950 to 3100 (Average reduction 20%)	Air to fuel change	Fuel consumption increase up to 10%; most suitable for turbocharged engines; may require increased maintenance; HC emissions increase, sometimes CO as well; technology demonstrated but not in use.

[a] Some equipment are outside this range.

[b] In some applications, emission levels less than those listed can be achieved.

TABLE 3-8-B. Continued

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Stationary compression ignition internal combustion engines -- oil-fired (diesel)	3.5 - ∿ 50 (1-∿15)	1150 - 3900	800 - 2750 (Average reduction 30%)	Retard	Fuel consumption increase of 2 to 8 percent; limited by deterioration of the exhaust valves and exhaust system; increased maintenance; limited by smoke, CO, HC emission increases; technology demonstrated but not in use.

a. Some equipment are outside this range.

b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-8-B. Concluded

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	**Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions**		**Available Control Technology**	**Application Comments**
		Base[a]	**Controlled**[b]		
Stationary compression ignition internal combustion engines -- oil-fired (diesel)	3.5 - $\sim$ 50 (1-$\sim$15)	1150 - 3900	700 - 2300 (Average reduction 40%)	Retard and air-fuel ratio changes	Increase in fuel consumption of 3 to 5%; increased maintenance; possible increase in HC, CO and smoke emissions; technology demonstrated, but not in use.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-8-C. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Stationary compression ignition internal combustion engines - dual fuel (gas & oil)	3.5 - ∿ 50 (1-∿15)	1075 - 3275	860 - 2600 (Average reduction 20%)	External exhaust gas recirculation	Increase in fuel consumption up to 1%; increased maintenance; CO, smoke levels also increase; technology demonstrated but not in use; could be retrofit problems.
			860 - 2600 (Average reduction 20%)	Derate	Need extra engine capacity; fuel consumption increase up to 8%; technology demonatrated but not in use.
			860 - 2600 (Average reduction 20%)	Manifold air cooling	Increases HC and CO emissions; fuel consumption increase of 1%; technology demonstrated but not in use; increased cooling system maintenance; could be retrofit problem.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-8-C. Concluded

STATIONARY INTERNAL COMBUSTION ENGINES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Stationary compression ignition internal combustion engines - dual fuel (oil & gas)	3.5 to ~ 50 (1-~15)	1075 - 3275	750 - 2200 (Average reduction 30%)	Retard	2% increase in fuel consumption; possible deterioration of exhaust valves and exhaust system; requires increased maintenance; smoke at high retard levels; technology demonstrated but not in use; possible CO, HC increases.
			750 - 2200 (Average reduction 30%)	Air to fuel change	Increase in fuel consumption up to 2%; limited by misfiring; increase in HC and CO emissions; technology demonstrated but not in use; best for turbocharged engines.
			650 - 1900 (Average reduction 40%)	Retard and air fuel change	Fuel consumption increases of 1 to 3%; emissions of HC, CO and smoke increase; increased maintenance required; technology demonstrated but not in use.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-9. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

GLASS MELTING FURNACES

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Glass melting furnace - natural gas fired	50 (15)	490-700	192-219 (Average reduction 65%)	Low O_2 and electric boost.	Generally applicable; increases use of electricity; possible limitations to retrofit old furnaces; controlled emissions data based on one test. One source (Reference 43) indicated that this technology is suitable for container glass production but not for flat glass manufacturing.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

TABLE 3-10. AVAILABLE CONTROL TECHNOLOGY RELATED TO NO_x STATIONARY SOURCE RETROFIT EMISSION LIMITS NOT REQUIRED BY SCAQMD SIP

CEMENT KILNS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Cement kilns wet process - natural gas fired	75-350 (22-103)	2548	2134 (Average reduction 15%)	Simultaneous reduction in excess O_2 and increasing combustion air temperature (Combustion modification)	Possible limitations to combustion modifications due to process constraints; to maintain process chemistry, combustion air temperature, kiln temperature and exit gas O_2 concentration can not be varied independently; fuel switch, natural gas to oil, is a possible control technique, but no data is available; controlled emissions data based on one test.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

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TABLE 3-10. Concluded

CEMENT KILNS

Category	Capacity: Max. Heat Input - 10^6 Btu/hr (MW)	Emissions: ppm NO_x, dry, at 3% O_2, measured at steady state equipment operating conditions		Available Control Technology	Application Comments
		Base[a]	Controlled[b]		
Cement kilns dry process - natural gas fired	75-350 (22-103)	1680-5200	600-1085 (Average reduction 65%)	Fuel switch natural gas to oil	Generally applicable; due to decreasing availability of natural gas to industrial facilities, trend is apparently towards burning oil or solid fuels. Burner modification, additional fuel handling equipment and fuel storage areas will be needed.
		1460	1065 (Average reduction 25%)	Fuel switch from natural gas to gas	Controlled emissions data based on one test. Burner modification, additional fuel handling equipment and fuel storage areas will be needed.
			Based on mass emission rates, an average 71% reduction in the mass of NO_x emissions reported as NO_2 is indicated	Fuel switch from natural gas to coal	Controlled emissions data obtained from seven cement kilns in the SCAQMD area. Burner modification, additional fuel handling equipment and fuel storage areas will be needed.

a. Some equipment are outside this range.
b. In some applications, emissions levels less than those listed can be achieved.

3.4 AVAILABLE CONTROL TECHNOLOGY COSTS AND COST EFFECTIVENESS

The procedure used to calculate the costs and cost effectiveness shown in this section is described in Appendix B. All costs are presented in terms of 1979 dollars.

3.4.1 Utility Boilers and Gas Turbines

The estimated cost and cost effectiveness of NO_x controls for oil- and gas-fired utility boilers and gas turbines are listed in Table 3-11 for gas-fired utility boilers, Table 3-12 for oil-fired utility boilers, and Table 3-13 for gas turbines.

Utility boiler control costs were compiled from estimates collected from utilities (References 1 through 10) and are based on actual application of the identified ACT on utility boilers. In calculating the annualized costs, a factor of 25 percent is used to annualize the capital costs along with a load factor of 50 percent as suggested by Reference 38. The fuel costs used are $\$2.00/10^6$ Btu for natural gas and $\$3.25/10^6$ Btu for residual oil based on higher heating value.

It should not be concluded that the ACT for which cost and cost effectiveness are discussed in Tables 3-11 and 3-12 can reasonably be expected to be applied to a given utility boiler. A number of source and site-specific problems could prevent the application of any of the ACT discussed. In Tables 3-12 and 3-13, the cost effectiveness is given for adding controls to uncontrolled boilers. If the boilers are already controlled by combined combustion modification techniques, the cost effectiveness of adding noncatalytic ammonia injection to a gas-fired boiler is \$4000 to \$10,000/ton NO_x reduced (\$4,400 to \$11,000 g/Mg) and to an oil-fired unit is \$3000 to \$5000/ton NO_x reduced (\$3,300 to \$5,500 g/Mg). For adding selective catalytic reduction, the cost effectiveness is \$15,000 to \$25,000/ton NO_x reduced (\$16,500 to \$27,500 g/Mg) for a gas-fired boiler and \$9000 to \$13,000/ton NO_x reduced (\$9,900 to \$14,300 g/Mg) for an oil-fired unit.

The estimated cost and cost effectiveness of controlling NO_x in large size gas turbines is presented in Table 3-13. These costs are compiled from utilities' estimates (References 15 to 27). Costs are not presented for the smaller sized turbines because cost data for actual application of water injection to these units is very limited. In calculating the costs a factor of 25 percent is used to annualize the fixed cost and fuel is assumed to cost $\$2.10/10^6$ Btu for natural gas and $\$4.25/10^6$ Btu for distillate oil based on lower heating values.

Following is an explanation of the information presented in Tables 3-11 and 3-12 for gas-fired and oil-fired utility boilers:

- The first column specifies the heat input capacity of the equipment being costed
- In the next two columns, the emission level in ppm (and also the percent average reduction) and the ACT that is applied to obtain the emission level are specified. The percent average reduction is average in the sense that it is the reduction from the base case that can be expected by application of the ACT on the average utility boiler. Footnote "a" on each table identifies the source of additional information concerning the ACT.
- The next three columns relate to costs in terms of electrical energy produced. Estimates are presented for capital costs, annual operating costs, and total annual costs. Total annual costs are the sum of annual operating costs plus annualized capital costs. See Appendix B for further explanation.
- The next two columns present the ACT cost effectiveness in terms of total annual cost per ton of NO_x reduced per year for the case where the control is retrofitted to an uncontrolled boiler. These data are presented in terms of a range and an average. The cost effectiveness for each ACT is shown as a range because the total annual costs may vary and/or the yearly NO_x emission reductions vary, thus producing a range of cost effectiveness. The total annual cost and emission reduction variability results from the site specific variables associated with ACT retrofit applications.
- The last column lists applicable references.

TABLE 3-11. ESTIMATED COST AND COST EFFECTIVENESS OF RETROFITTED ACT CONTROLS FOR GAS-FIRED UTILITY BOILERS

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)[d]			Cost Effectiveness[d]: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
1488 (436)	300 to 680 (15% average reduction	Low Excess Air	0.75	-0.04 to -0.53	-0.49 to 0	-1655 to 0 (-1823 to 0)	-830 (-918)	1, 2, 5
	225 to 520 (35% average reduction)	Burners out of Service or Biased Burner Firing	0.20	0.05	0.06	35 to 80 (38 to 89)	60 (68)	1,5
	175 to 400 (50% average reduction)	Low NO_x Burner	NA[e]	NA	NA	NA	NA	--
	175 to 400 (50% average reduction)	Overfire Air	0.36 to 1.78	0.043 to 0.09	0.06 to 0.19	35 to 190 (38 to 208)	110 (122)	1,3,5,6
	175 to 400 (50% average reduction)	Flue Gas Recirculation	4.9 to 10.4	0.26 to 0.49	0.57 to 1.14	245 to 1100 (267 to 1212)	675 (744)	1,4,6
	175 to 400 (50% average reduction)	Reduced Load	--	2.8 (purchased power) -- fuel credit	2.8	1175 to 2700 (1295 to 2975)	1960 (2157)	1
	100 to 150 (70% average reduction)	Combined Combustion Modification Controls	5.3 to 12	0.36 to 0.50	0.67 to 1.20	180 to 810 (198 to 892)	505 (558)	1,4,5,6
	60 to 90 (85% average reduction)	Noncatalytic Ammonia Injection plus Combined Controls	31 to 42	1.12 to 1.26	2.9 to 3.7	595 to 1850 (574 to 2025)	1215 (1350)	8,10
	10 to 15 (97% average reduction)	Selective Catalytic plus Combined Combustion Modifications	130 to 137	6.7 to 6.9	14.2 to 14.7	3050 to 8200 (3355 to 9020)	5600 (6160)	9,10

[a] See Table 3-3-G for additional information.

[b] Load factor of 50% is used.

[c] Factor of 25% is used to annualize capital costs.

[d] A negative sign (-) indicates a cost saving or cost effectiveness improvement.

[e] NA = not available (no information found)

TABLE 3-11. Continued

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)[e]			Cost Effectiveness[e]: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
2000 (586)	300 to 680 (15% average reduction)	Low Excess Air	0.54	-0.04 to -0.53[d] (for increase in thermal efficiency of 0.5 to 5%)	-0.50 to 0	-1655 to 0 (-1825 to 0)	-615 (-830)	1,2,5
	225 to 520 (35% average reduction)	Biased Burner Firing	NA[f]	NA (Probably the same as BOOS)	NA	NA	NA	--
	225to 520 (35% average reduction)	Burners out of Service (BOOS)	0.15	0.05	0.06	35 to 80 (38 to 89)	60 (68)	1,5
	175 to 400 (50% average reduction)	Low NO_x Burners	NA	NA	NA	NA	NA	--
	175 to 400 (50% average reduction)	Overfire Air	0.27 to 1.3	0.043 to 0.09	0.06 to 0.17	35 to 170 (38 to 186)	100 (110)	1,3,5,6
	175 to 400 (50% average reduction)	Flue Gas Recirculation	3.6 to 7.7	0.26 to 0.49	0.47 to 0.94	205 to 905 (223 to 996)	540 (595)	1,4,6
	175 to 400 (50% average reduction)	Reduced Load	--	2.8	2.8	1175 to 2700 (1295 to 2975)	1960 (2157)	1

[a] See Table 3-3-6 r additional information
[b] Load factor of 50% is used
[c] Factor of 25% is used to annualize capital costs
[d] Includes 5% of capital cost
[e] A negative sign (-) indicates a cost saving
[f] NA = not available (no information found)

TABLE 3-11. Continued

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)			Cost Effectiveness: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
2000 (586)	100 to 150 (75% average reduction)	Combined Combustion Modification Controls	3.9 to 8.8	0.36 to 0.50	0.59 to 1.01	155 to 675 (171 to 744)	405 (447)	1,4,5,6
	60 to 90 (85% average reduction)	Noncatalytic Ammonia Injection plus Combined Controls	24 to 34	0.72 to 1.22	2.12 to 3.20	505 to 1855 (558 to 2045)	1180 (1301)	8,10
	10 to 15 (97% average reduction)	Selective Catalytic Reduction plus Combined Combustion Modification	119 to 124	6.7 to 6.9	13.5 to 14.0	2900 to 8100 (3190 to 8910)	5500 (6050)	9,10

[a] See Table 3-3-G for additional information

[b] Load factor of 50% is used

[c] /factor of 25% is used to annualize capital costs

TABLE 3-11. Continued

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)[e]			Cost Effectiveness[e]: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
4440 (1301)	300 to 680 (15% average reduction)	Low Excess Air	0.34	-0.04 to -0.53[d] (for increase in thermal efficiency of 0.5 to 5%)	-0.50 to -0.02	-1655 to 0 (-1825 to 0)	-615 (-830)	1,2,5
	225 to 520 (35% average reduction)	Burners out of Service or Biased Burner Firing	0.10	0.05	0.06	35 to 80 (38 to 89)	60 (68)	1,5
	175 to 400 (50% average reduction)	Overfire Air	0.17 to 0.83	0.043 to 0.09	0.05 to 0.14	35 to 135 (38 to 150)	80 (89)	1,3,5,6
	175 to 400 (50% average reduction)	Flue Gas Recirculation	2.3 to 4.9	0.26 to 0.49	0.39 to 0.77	160 to 745 (178 to 818)	450 (498)	1,4,6
	175 to 400 (50% average reduction)	Reduced Load	--	2.8	2.8	1175 to 2700 (1295 to 2975)	1960 (2157)	1
	175 to 400 (50% average reduction)	Low NO_x Burners	NA[f]	NA	NA	NA	NA	--

[a] See Table 3-3-G for additional information
[b] Load factor of 50% is used
[c] Factor of 25% is used to annualize capital costs
[d] Includes 5% of capital cost
[e] A negative sign (-) indicates a cost saving
[f] NA = not available (no information found)

TABLE 3-11. Concluded

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)			Cost Effectiveness: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
4440 (1301)	100 to 150 (75% average reduction)	Combined Combustion Modification Controls	2.5 to 5.6	0.36 to 0.50	0.51 to 0.83	135 to 555 (149 to 610)	340 (373)	1,4,5,6
	60 to 90 (85% average reduction)	Noncatalytic Ammonia Injection plus Combined Combustion Modification	16.5 to 23.6	1.59 to 1.73	2.55 to 3.10	610 to 1825 (670 to 2009)	1215 (1339)	8,10
	10 to 15 (97% average reduction)	Selective Catalytic Reduction plus Combined Combustion Modification	103 to 106	6.7 to 6.9	12.6 to 12.9	2700 to 7500 (2970 to 8250)	5100 (5610)	9,10

[a] See Table 3-3-G for additional information

[b] Load factor of 50% is used

[c] Factor of 25% is used to annualize capital costs

TABLE 3-12. ESTIMATED COST AND COST EFFECTIVENESS OF RETROFITTED ACT CONTROLS FOR OIL-FIRED UTILITY BOILERS

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)			Cost Effectiveness[e]: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
1488 (436)	300 to 400 (15% average reduction)	Low Excess Air	0.75	-0.15 to -1.62[d] (for increase in thermal efficiency of 0.5 to 5%)	-0.10 to -1.58	-5000 to 0 (-5500 to 0)	-2500 (-2750)	1,2,5
	300 to 425 (15% average reduction)	Flue Gas Recirculation (FGR)	4.9 to 10.4	0.26 to 0.49	0.57 to 1.14	1140 to 2700 (1256 to 2975)	1900 (2094)	1,4,6
	250 to 350 (30% average reduction)	Biased Burner Firing or Burners out of Service	0.20	0.07	0.08	80 to 120 (88 to 132)	100 (110)	1,5
	250 to 350 (30% average reduction)	Overfire Air Injection	0.36 to 1.78	0.043 to 0.15	0.06 to 0.25	60 to 375 (66 to 413)	225 (248)	1,3,5,6
	250 to 350 (30% average reduction)	Reduced Load	--	2.8 (purchased power -- fuel credit)	2.8	2800 to 4200 (3086 to 4628)	3500 (3857)	1
	225 to 300 (35% average reduction)	Low NO_x Burners	NA[f]	NA	NA	NA	NA	--

[a] See Table 3-3-H for additional information
[b] Load factor of 50% is used
[c] Factor of 25% is used to annualize capital costs
[d] Includes 5% of capital cost
[e] Negative sign (-) indicates a cost savings or a cost effectiveness improvement
[f] NA = not available (no information found)

TABLE 3-12. Continued

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)			Cost Effectiveness: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
1488 (436)	200 to 250 (45% average reduction)	Combined Combustion Modification Control	5.3 to 12	0.36 to 0.5	0.67 to 1.20	400 to 1000 (441 to 1102)	700 (771)	1,4,5,6
	120 to 150 (65% average reduction)	Noncatalytic Ammonia Injection plus Combined Combustion Modification	31 to 42	1.76 to 1.9	3.5 to 4.3	1500 to 2800 (1650 to 3080)	2200 (2400)	8,10
	20 to 25 (95% average reduction)	Selective Catalytic Reduction plus Combined Combustion Modification	129 to 137	8.0 to 8.2	15.4 to 16.0	5000 to 7400 (5500 to 8140)	6200 (6820)	9,10

[a] See Table 3-3-H for additional information

[b] Load factor of 50% is used

[c] Factor of 25% is used to annualize capital costs

TABLE 3-12. Continued

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)[e]			Cost Effectiveness[e]: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
2000 (586)	300 to 400 (15% average reduction)	Low Excess Air	0.54	-0.15 to -1.62[d] (for increase in thermal efficiency of 0.5 to 5%)	-0.12 to -1.59	-5000 to 0 (-5000 to 0)	-2500 (-2750)	1,2,5
	300 to 425 (15% average reduction)	Flue Gas Recirculation	3.6 to 7.7	0.26 to 0.49	0.47 to 0.94	940 to 2820 (1036 to 3108)	1900 (2094)	1,4,6
	250 to 250 (30% average reduction)	Burners out of Service or Biased Burner Firing	0.15	0.07	0.08	13 to 80 (14 to 88)	45 (50)	1,5
	250 to 350 (30% average reduction)	Overfire Air (OFA)	0.27 to 1.3	0.043 to 0.15	0.06 to 0.23	60 to 345 (66 to 380)	200 (220)	1,3,5,6

[a] See Table 3-3-H for additional information
[b] Load factor of 50% is used
[c] Factor of 25% is used to annualize capital costs
[d] Includes 5% of capital cost
[e] A negative sign (-) indicates a cost savings or a cost effectiveness improvement

TABLE 3-12. Continued

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)			Cost Effectiveness: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
2000 (586)	250 to 350 (30% average reduction)	Reduced Load	--	2.8	2.8	2800 to 4200 (3086 to 4628)	3500 (3857)	1
	225 to 300 (35% average reduction)	Low NO_x Burners	NA[d]	NA	NA	NA	NA	--
	200 to 250 (45% average reduction)	Combined Combustion Modifications (OFA and FGR)	3.9 to 8.8	0.36 to 0.50	0.59 to 1.01	355 to 1000 (391 to 1102)	700 (771)	1,4,5,6
	120 to 150 (65% average reduction)	Noncatalytic Reduction plus Combined Combustion Modification Controls	24 to 33.8	1.71 to 1.85	3.11 to 3.83	1400 to 2600 (1540 to 2860)	2000 (2200)	8,10
	20 to 25 (95% average reduction)	Selective Catalytic Reduction plus Combined Combustion Modification	119 to 124	8.0 to 8.2	14.8 to 15.2	4800 to 7000 (5280 to 7700)	5900 (6490)	9,10

[a] See Table 3-3-H for additional information
[b] Load factor of 50% is used
[c] Factor of 25% is used to annualize capital costs
[d] NA = not available (no information found)

TABLE 3-12. Continued

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)[d]			Cost Effectiveness[d]: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
4440 (1301)	300 to 400 (15% average reduction)	Low Excess Air	0.34	-0.15 to -1.62	-0.10 to -1.58	-5000 to 0 (-5500 to 0)	-2500 (-2750)	1,2,5
	300 to 425 (15% average reduction)	Flue Gas Recirculation	2.3 to 4.9	0.26 to 0.49	0.39 to 0.77	780 to 2325 (860 to 2562)	1550 (1708)	1,4,6
	250 to 350 (30% average reduction)	Overfire Air	0.17 to 0.83	0.043 to 0.15	0.05 to 0.20	50 to 75 (55 to 83)	65 (72)	1,3,5,6
	250 to 350 (30% average reduction)	Biased Burner Firing or Burners out of Service	0.10	0.07	0.08	75 to 120 (83 to 132)	100 (110)	1,5

[a] See Table 3-3-H for additional information
[b] Load factor of 50% is used
[c] Factor of 25% is used to annualize capital costs
[d] A negative sign (-) indicates a cost saving or cost effectiveness improvement

TABLE 3-12. Concluded

Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, dry at Steady State Operation	ACT[a] applied	Costs: (1979$)			Cost Effectiveness: $/ton NOx Reduced ($/Mg)		References
			Capital: $/kW electrical	Annual Operating:[b] mills/kW-hr electrical	Total Annual:[b,c] mills/kW-hr electrical	Range	Average	
4440 (1301)	250 to 350 (30% average reduction)	Reduced Load	--	2.8	2.8	2800 to 4200 (3086 to 4628)	3500 (3857)	1
	225 to 300 (35% average reduction)	Low NO_x Burners	NA[d]	NA	NA	NA	NA	--
	200 to 250 (45% average reduction)	Combined Combustion Modifications (OFA and FGR)	2.5 to 5.6	0.36 to 0.50	0.51 to 0.83	305 to 1240 (336 to 1366)	770 (849)	1,4,5,6
	120 to 150 (65% average reduction)	Noncatalytic Ammonia Injection plus Combined Combustion Modification	16.5 to 23.6	1.59 to 1.73	2.55 to 3.10	1100 to 2000 (1210 to 2200)	1550 (1700)	8,10
	20 to 25 (95% average reduction)	Selective Catalytic Reduction plus Combined Combustion Modification	103 to 106	8.0 to 8.2	13.9 to 14.2	4500 to 6600 (4950 to 7260)	5500 (6050)	9,10

[a] See Table 3-3-H for additional information

[b] Load factor of 50% is used

[c] Factor of 25% is used to annualize capital costs

[d] NA = not available (no information found)

Following is an explanation of the information presented in Table 3-13 for gas turbines:

- The first column specifies the type of fuel used to fire the gas turbine and the heat input capacity of the equipment being costed.
- In the next two columns, the emission level in ppm (and also as percent average reduction) and the ACT that is applied to obtain the emission level are specified. The percent average reduction is average in the sense that it is the reduction from the base case that can be expected by application of the ACT on the average utility boiler. Footnote "a" on the table identifies the source of additional information concerning the ACT.
- The next column titled "Load Factor" specifies the percent of time that a turbine is in operation during the year. The 6 percent load factor represents that of a typical utility peaking unit and the 90 percent load factor represents that of a typical utility base load unit.
- The next three columns relate to costs in terms of electrical energy produced. Estimates are presented for capital costs, annual operating costs, and total annual costs. Total annual costs are the sum of annual operating plus annualized capital costs. See Appendix B for further explanation.
- The last two columns present the ACT cost effectiveness in terms of total annual cost per ton of NO_x reduced per year. These data are presented in terms of a range and an average. The cost effectiveness for each ACT is shown as a range because the total annual costs vary and the yearly NO_x emission reductions also vary, thus producing a range of cost effectiveness. This total annual cost and emission reduction variability results from the site specific variables associated with ACT retrofit applications.

TABLE 3-13. ESTIMATED COST AND COST EFFECTIVENESS OF RETROFITTED ACT CONTROLS FOR GAS TURBINES

Fuel Type and Turbine Capacity: Heat Input 10^6 Btu/hr (MW)	Emission Level: NO_x ppm at 3% O_2, Dry at Steady State Operation	ACT[a]	Load Factor %	Costs: (1979$)[c]			Cost Effectiveness:	
				Capital $/kw Electrical	Annual Operating Mills/kw-hr Electrical	Total Annual[b] Mills/kw-hr Electrical	$/ton NO_x Reduced ($/Mg)	
							Range	Average
Oil fired 500 (146)	150 to 300 (average reduction of 50%)	Water injection	6	10 to 25	2.5	7.5 to 15	3500 to 14000 (3857 to 15428)	9000 (9918)
			90	10 to 25	1.8	2.1 to 2.6	800 to 2500 (882 to 2755)	1700 (1873)
Gas Fired 500 (146)	150 to 200 (Average reduction of 50%)	Water injection	6	10 to 25	2.0	7 to 14	6000 to 15000 (6612 to 16530)	12000 (13224)
			90	10 to 25	0.6	0.9 to 1.4	700 to 1500 (771 to 1653)	1200 (1322)

[a] See Table 3-5 for additional information

[b] Factor of 25% is used to annualize capital costs

[c] Costs from References 15 to 27

3.4.2 Refinery Process Heaters, Industrial Boilers, Stationary Internal Combustion Engines, Glass Melting Furnaces, Cement Kilns

The costs estimated for these source categories are very approximate because very few of these sources have had ACT applied. Also, retrofit applications and costs are very site specific. It should not be concluded that the ACT related to these source categories can necessarily be applied on a retrofit basis. For any given facility or source, equipment design, equipment operating, or space constraints could prevent the application of the ACT. The ranges of costs presented for the following source categories are the result of the cost variability due to site specific problems and limitations, as well as baseline NO_x emission variations. The typical cost effectiveness would tend to be toward the lower (i.e., increased effectiveness) end of the range.

Refinery Process Heaters

The cost data available were very limited and dated (Reference 28). The capital cost is annualized at a rate of 25 percent, and, in all cases, no loss of fuel efficiency was assumed. A standard heater size of 100×10^6 Btu/hr is used with a load factor of 90 percent.

Using burners out of service or low excess air for both natural and forced draft heaters will decrease emissions by 10 percent with a cost effectiveness of $400 to $4,000/ton ($440 to $4,400/Mg) of NO_x. For mechanical draft heaters, an emission reduction of 90 percent using selective catalytic reduction is expected to cost about $8,000 to $17,000/ton ($8,800 to $18,700/Mg) NO_x.

Industrial Boilers

Cost estimates for installing NO_x controls on industrial boilers were made using the data in References 8, 11, 32, and 33. Since this data is for new units, the capital cost of retrofitted controls is assumed to be 4 times as large. The capital cost is annualized at a rate of 25 percent per year and fuel prices used are $\$2.00/10^6$ Btu for natural gas, $\$3.25/10^6$ Btu for residual oil, and $\$4.00/10^6$ Btu for distillate oil based on higher heating values. A load factor of 50 percent is used. Estimated cost effectiveness for these boilers is found in Table 3-14. These costs are only for typical boilers; for some boilers site specific factors could cause the cost to be much higher.

Stationary Internal Combustion Engines

The estimated cost effectiveness of controlling NO_x in internal combustion engines comes from References 36 and 37. Retrofitted controls are assumed to cost 4 times the capital cost of new controls. A factor of 25 percent is used to annualize the capital costs and a load factor of 90 percent is used. Fuel costs are $\$4.25/10^6$ Btu for oil and $\$2.10/10^6$ Btu for natural gas based on lower heating values. Table 3-15 lists the estimated cost effectiveness.

Glass Melting Furnace

Assuming 8,000 hours/year operation and a 25 percent factor to annualize capital costs, the cost effectiveness for 60 percent NO_x reduction by use of low excess air and electric boost is \$4,000 to \$6,500/ton NO_x (4400 to 7150 \$/Mg) reduced. Fuel and electric energy costs are $\$2.00/10^6$ Btu for natural gas based on the higher heating value and \$0.03/kWh for electricity. The cost data are from Reference 28.

Cement Kilns (Dry Process)

The control technology demonstrated to reduce NO_x emissions from cement kilns is to switch fuel from natural gas to distillate oil. 8000 hours/year operation is assumed. The calculations are for a cement kiln of 200 million Btu/hr. Fuel costs are estimated to be $\$4.00/10^6$ Btu for oil and $\$2.00/10^6$ Btu for natural gas based on higher heating value.

The cost effectiveness calculated on this basis ranges from \$900/ton to \$3,500/ton (\$990 to \$3850/Mg) of NO_x reduced for 60 percent reduction. The cost data are from Reference 28.

3.5 NATIONWIDE NO_x EMISSION CONTROL RULE SURVEY

A state (or local district) may establish NO_x emission control rules which apply to existing sources or which apply to new sources and are stricter than the federal standards for new sources (New Source Performance Standards). Table 3-16 summarizes state and local NO_x regulations outside California for stationary combustion sources. Table 3-17 lists NO_x regulations applying to existing stationary combustion sources in California.

These data and information were obtained from the Environmental Reporter and from personal phone calls. New Source Review procedure regulations based on the California Air Resources Board new source review procedure model rule are being adopted throughout the state.

TABLE 3-14. ESTIMATED COST EFFECTIVENESS OF RETROFITTED NO_x CONTROLS FOR INDUSTRIAL BOILERS

Type	Fuel	Size-Heat Input 10^6 Btu/hr (MW)	NO_x Reduction Percent	Techniques	Cost Effectiveness[a] $/ton ($/Mg)
Firetube	Residual oil	15 (4.4)	5 to 20	Low excess air or flue gas recirculation	8,000 to 15,000 (9,000 to 16,000)
			40	Staged combustion air	4,000 to 10,000 (4,000 to 11,000)
	Distillate oil	15 (4.4)	5 to 35	Low excess air or staged combustion air	8,000 to 10,000 (9,000 to 11,000)
			40 to 50	Flue gas recirculation	5,000 to 10,000 (6,000 to 11,000
	Natural gas	15 (4.4)	5 to 35	Low excess air or staged combustion air	20,000 to 40,000 (22,000 to 44,000)
			50 to 55	Flue gas recirculation	8,000 to 15,000 (9,000 to 16,000)
Watertube	Residual oil	150 (44)	10 to 25	Low excess air or burners out of service, or flue gas recirculation	0 to 7,000 (0 to 8,000
			40	Staged combustion air with or without flue gas recirculation	500 to 7,000 (600 to 8,000
			90	Selective catalytic reduction	6,000 to 35,000 (7,000 to 38,000)

[a] Operating and capital costs from References 8, 11, 32 and 33

TABLE 3-14. Concluded

Type	Fuel	Size-Heat Input 10^6 Btu/hr (MW)	NO_x Reduction Percent	Techniques	Cost Effectiveness[a] $/ton ($/Mg)
Watertube without air preheater	Distillate oil	50 (15)	10 to 15	Low excess air	1,000 to 5,000 (1,000 to 6,000)
			25 to 45	Staged combustion air	4,000 to 10,000 (4,000 to 11,000)
			50 to 65	Flue gas recirculation with or without staged combustion air	6,000 to 10,000 (7,000 to 11,000)
Watertube with air preheater	Distillate oil	100 (29)	5 to 35	Low excess air or reduced preheat, or staged combustion air	500 to 20,000 (600 to 22,000)
			50 to 65	Flue gas recirculation with or without staged combustion air	1,500 to 7,000 (1,600 to 8,000)
			90	Selective catalytic reduction	12,000 to 35,000 (13,000 to 38,000)
Watertube without air preheater	Natural gas	50 (15)	5 to 25	Low excess air or staged combustion air	1,000 to 20,000 (1,000 to 22,000)
			40 to 60	Flue gas recirculation with or without staged combustion air	1,500 to 12,000 (1,600 to 13,000)
Watertube with air preheater	Natural gas	100 (29)	5 to 10	Low excess air or reduced air preheat	500 to 20,000 (600 to 22,000)
			25	Staged combustion air	500 to 5,000 (600 to 6,000)
			60	Flue gas recirculation and staged combustion air	500 to 5,000 (600 to 6,000)
			90	Selective catalytic reduction	8,000 to 50,000 (9,000 to 55,000)

[a] Operating and capital costs from References 8, 11, 32 and 33

TABLE 3-15. ESTIMATED COST EFFECTIVENESS OF RETROFITTED NO_x CONTROLS FOR STATIONARY INTERNAL COMBUSTION ENGINES (10 x 10^6 Btu/hr HEAT INPUT (3 MW))

Type	NO_x Reduction Percent	Techniques	Cost Effectiveness[a] \$/ton (\$/Mg)
Natural gas engine	20	Retard, or manifold air cooling increase, or exhaust gas recirculation	200 to 2,500 (220 to 2,750)
	30	Air-to-fuel changes	200 to 500 (220 to 550)
	40	Retard, increased manifold air cooling, and air-to-fuel change combined	400 to 1,000 (440 to 1,100)
Diesel engine	20	Exhaust gas recirculation, or manifold air cooling increase, or air-to-fuel changes	400 to 3,000 (440 to 3,300)
	30	Retard	1,000 to 2,500 (1,100 to 2,750)
	40	Retard and air-to-fuel ratio change	500 to 1,500 (550 to 1,650)
Dual fuel engine	20	Exhaust gas recirculation, or manifold air cooling increase	1,000 to 4,000 (1,100 to 4,400)
	30	Retard, or air-to-fuel ratio changes	100 to 500 (110 to 550)
	40	Retard and air-to-fuel ratio change	500 to 1,500 (550 to 1,650)

[a] Capital and operating costs are from References 36 and 37

TABLE 3-16. NON-CALIFORNIA STATE AND LOCAL NO_x REGULATIONS FOR STATIONARY COMBUSTION SOURCES (STRICTER THAN FEDERAL STANDARDS)

State	Equipment			NO_x Emission Standard[a] lb/10^6 Btu (ng/J)			Comments
	New or Existing	Type	Heat Input Capacity: 10^6 Btu/hr (MW)	Gas-Fired	Oil-Fired	Coal-Fired	
Arizona	All	Steam power generators	--	0.2 (86.1)	0.3 (129)	0.7 (387.3)	None
Connecticut	All	Fuel burning	≥250 (≥73)	0.2 (86.1)	0.3 (129)	0.9 (387.3)	Except gas turbines and internal combustion engines
	New	Fuel burning	5-250 (1.5-73)	0.2 (86.1)	0.3 (129)	0.7 (301)	Except gas turbines and internal combustion engines
	Existing	Fuel burning	5-250 (1.5-73)	0.2 (86.1)	0.3 (129)	0.9 (387.3)	Except gas turbines and internal combustion engines
	All	Gas turbine		0.9 (387.3)	0.9 (387.3)		Variances permitted
Delaware New Castle County	All	Fuel burning equipment	>500 (>147.5)	0.2 (86.1)	0.3 (129)	0.7 (129)	Except for certain sources governed by operation permit
District of Columbia	All	Steam Generators	>100 (>29)	0.2 (86.1)	0.3 (129)	0.7 (301)	Except lignite
Florida Tampa	Existing	Steam boilers	>250 (>73)	0.2 (86.1)	0.3 (129)	0.7 (301)	None

[a] See Appendix A for procedures and factors for conversion of lb $NO_x/10^6$ Btu standard to NO_x ppm units.

TABLE 3-16. Continued

State	Equipment			NO_x Emission Standard[a] lb/10^6 Btu (ng/J)			Comments
	New or Existing	Type	Heat Input Capacity: 10^6 Btu/hr (MW)	Gas-Fired	Oil-Fired	Coal-Fired	
Illinois: Lake, Will, DuPage, McHenry, Kara, Grundy, Kendal, Kankakee, Macon, St. Clair, Madison Counties	Existing	Fuel combustion	≥250 (≥73)	0.3 (129)	0.3 (129)	0.9 (387.3)	Except cyclone and horizontally opposed fired boilers burning solid fuel
Cook Co.	New	Fuel combustion	≥200 (≥59)	0.2 (86.1)	0.3 (129)	0.7 (301)	
	Existing	Fuel combustion	≥200 (≥59)	0.3 (129)	0.3 (129)	0.9 (387.3)	Same as above
Indiana	Existing	Fuel burning	≥250 (≥73)	0.2 (86.1)	0.3 (129)	0.7 (301)	None
Kansas	All	Indirect heating equipment	≥250 (≥73)	0.3 (129)	0.3 (129)	0.9 (387.3)	None
Maryland	New	Fuel burning	≥250 (≥73)	0.2 (86.1)	0.3 (129)	0.5 (215.2)	Applies to priority I AQCR's only
North Carolina	Existing	Boilers	≥250 (≥73)	0.6 (258.2)	0.6 (258.2)	1.3 (559.4)	
	New	Boilers	≥250 (≥73)	0.2 (86.1)	0.3 (129)	0.7 (301)*	*solid fuels -- except lignite

[a] See Appendix A for procedures and factors for conversion of lb NO_x/10^6 Btu standard to NO_x ppm units.

TABLE 3-16. Continued

State	Equipment			NO_x Emission Standard[a] $lb/10^6$ Btu (ng/J)			Comments
	New or Existing	Type	Heat Input Capacity: 10^6 Btu/hr (MW)	Gas-Fired	Oil-Fired	Coal-Fired	
New Mexico	New	Coal burning	≥250 (≥73)			0.45 (193.6)	None
	Existing	Coal burning	≥250 (≥73)			0.7 (301)	
	New	Gas burning	≥1,000,000 10^6Btu/yr ≥1,055,000 GJ/yr	0.2 (86.1)			
	Existing	Gas burning	≥1,000,000 10^6Btu/yr ≥1,055,000 GJ/yr	0.3 (129)			
	All	Oil burning	≥1,000,000 10^6Btu/yr ≥1,055,000 GJ/yr	0.3 (129)			
New York City	Existing	Boilers	≥500 (≥147.5)	150 ppm	150 ppm	150 ppm	Gas turbine and stationary internal combustion engines exempt
Ohio	Existing	Boilers	≥250 (≥73)	0.2 (86.1)	0.3 (129)	0.9 (387.3)	Applies to Priority I regions only
Oklahoma	New	Indirect heating equipment	≥50 (≥52.75)	0.2 (86.1)	0.3 (129)	0.7 (301)	Includes internal combustion engines above 500 hp
Texas Dallas Fort Worth Houston Galveston AQCR's	All	Steam generators	≥600,000 lb steam/hr max (≥272,200 kg steam/hr max)				
		Opposed fired		0.7 (301)			Except existing gas-fired units 600,000 lbs/hr but 1,100,000 lbs/hr maximum. Exempt if steam generated does not exceed 30% of product
		Front fired		0.5 (215.2)			
		Tangential fired		0.25 (107.6)			

[a] See Appendix A for procedure and factors for conversion of lb $NO_x/10^6$ Btu standard to NO_x ppm limits.

TABLE 3-16. Concluded

State	Equipment			NO_x Emission Standard[a] lb/10^6 Btu (ng/J)			Comments
	New or Existing	Type	Heat Input Capacity: 10^6 Btu/hr (MW)	Gas-Fired	Oil-Fired	Coal-Fired	
Wyoming	New	Gas burning		0.2 (86.1)			Except Stationary Internal Combustion Engines < 59 MW
	Existing	Gas burning		0.23 (99)			
	New	Oil burning	≥1 (≥0.29)		0.3 (129)		Except Stationary Internal Combustion Engines <59 MW
	New	Oil burning	≥1 (≥0.29)		0.6 (258.2)		Except Stationary Internal Combustion Engines <59 MW
	Existing	Oil burning	≥250 (≥73)		0.46 (197.9)		Except Stationary Internal Combustion Engines <59 MW
	Existing	Oil burning	≥250 (≥73)		0.6 (258.2)		
	New	Solid fired equipment				0.7 (301)	
	Existing	Solid fired equipment				0.75 (322.7)	Except lignite

[a] See Appendix A for procedure and factors for conversion of lb $NO_x/10^6$ Btu to NO_x ppm limits.

TABLE 3-17. CALIFORNIA NO$_x$ REGULATIONS FOR EXISTING STATIONARY COMBUSTION SOURCES

Local Agency	Equipment		NO$_x$ Emission Standard		
	Type	Heat Capacity Input 10^6 Btu/hr (MW)	Gas-Fired	Oil-Fired	Coal-Fired
San Diego	Fuel burning	>50 (15)	125 ppm	225 ppm	225 ppm
San Joaquin	Fuel burning	>1775 (520)	125 ppm	225 ppm	225 ppm
San Luis Obispo	Fuel burning	>1775 (520)	300 ppm	300 ppm	300 ppm
South Coast, Los Angeles, Riverside and San Bernardino	Fuel burning	>555-1786 (163-523) 1786-2143 (523-628) ≥2143 (628)	300 ppm 225 ppm 125 ppm	400 ppm 325 ppm 225 ppm	400 ppm 325 ppm 225 ppm
Riverside and San Bernardino	Steam generating	>555 (163)	125 ppm	225 ppm	225 ppm
Orange	Fuel burning	>500-2150 (147-630) >2150 (630)	225 ppm 125 ppm	325 ppm 225 ppm	325 ppm 225 ppm
Tehama	Fuel burning	All	125 ppm	225 ppm	225 ppm
Tulare	Fuel burning	>1775 (520)	125 ppm	225 ppm	225 ppm
Bay Area	Heat transfer	>1750 (513)	175 ppm	300 ppm	--
Great Basin	Fuel burning	>1500 (440)	125 ppm	225 ppm	225 ppm
Kings County	Fuel burning	>1775 (520)	125 ppm	225 ppm	225 ppm
Madera County	Fuel burning	All	140 lb/hr (64 kg/hr)	140 lb/hr (64 kg/hr)	140 lb/hr (64 kg/hr)
Merced	Fuel burning	>1775 (520)	125 ppm	225 ppm	225 ppm
Monterey Bay	Fuel burning	>1500 (440)	225 ppm	225 ppm	225 ppm
Ventura	Fuel burning equipment	>2150 (630) >25	125 ppm 250 ppm	225 ppm 250 ppm	225 ppm 250 ppm
		all capacities	20 ton/day limit	20 ton/day limit	20 ton/day limit
Yolo-Solano	Fuel burning	All	140 lb/hr (64 kg/hr)	140 lb/hr (64 kg/hr)	140 lb/hr (64 kg/hr)

These New Source Review procedure regulations could likely require emission controls much stricter than the present new source NO_x emission limitations rules require and, thus, the new source NO_x emission limitation rules are not included.

A selected survey of these regulations revealed that, in general, the main compliance concern and effort relates to the control of NO_x emissions from large boilers. There appeared to be a concensus that the required control technology is not currently available for many source applications. Also, in most areas there did not appear to be a significant concern and emphasis relating to the control of NO_x emissions from smaller sources.

APPENDIX A

CALCULATION PROCEDURE FOR CONVERSION OF "MASS OF NO_x/UNIT OF HEAT ENERGY INPUT" TO ppm CONCENTRATION LIMIT

An example calculation for converting ng/J (i.e., ng of NO_x emissions per Joule of heat energy input) to a parts per million (ppm) concentration for a natural gas-fired boiler is shown below. The procedure is the same for residual or distillate oil-fired units.

Assuming natural gas to be composed mainly of methane, the combustion equation is:

$$CH_4 + 2O_2 = CO_2 + 2H_2O \qquad (1)$$

For the theoretical combustion of one cubic foot of natural gas with a heating value of 1030 Btu, 9.74 ft^3 of combustion air is required (or 9.74 ft^3 of air/ft^3 of natural gas). Therefore, for Eq. (1), assuming a dry basis and 1 ft^3 of natural gas:

1 ft^3 gas + 9.74 ft^3 air = 10.74 ft^3 total flue gas - 2 ft^3 H_2O gas = 8.74 ft^3 of flue gas (dry)

However, the ppm units are at 3 percent excess O_2, so that a correction for this excess air must be made. Assuming air is 21 percent O_2 and 79 percent N_2, the amount of excess air (x ft^3) is:

$$\frac{0.21\ (x)}{(1 + 9.74 + x - 2)} = 0.03 \qquad (2)$$

or x = 1.46, so that the actual amount of dry flue gas at 3 percent O_2 is:

$$8.74 + 1.46 = 10.20\ ft^3\ \text{flue gas}/ft^3\ \text{fuel}$$

At $32^{o}F$ and 1 atm, there are 359 ft^3 of an ideal gas per pound-mole. We will express the NO_x as NO_2 and assume it behaves as an ideal gas. So at $70^{o}F$, 1 lb-mole of this gas occupies

$$(359\ ft^3/lbmole)\ (530/492) = 387\ ft^3.$$

The molecular weight of NO_2 is 46 lb/lbmole, so that one pound of NO_2 occupies:

$$387\ ft^3/lb\ mole \times \frac{lb\ mole}{46\ lb} = 8.4\ ft^3/lb\ NO_2.$$

So now the conversion is (for this example we are converting 86 ng/J to ppm; and assuming natural gas has a heating value of 1030 Btu/ft^3):

$$\left(\frac{86\ ng\ NO_2}{J}\right)\left(\frac{1\ lb}{10^6\ Btu} \cdot \frac{1\ J}{430\ ng}\right)\left(\frac{1030\ Btu}{ft^3\ fuel}\right)\left(\frac{1\ ft^3 fuel}{10.2\ ft^3\ flue\ gas}\right)\left(\frac{8.4\ ft^3\ NO_2}{1\ lb\ NO_2}\right)$$

$$= 0.000169\ \frac{ft^3\ NO_2}{ft^3\ flue\ gas}$$

$$= 169\ ppm\ NO_x$$

Thus, to convert from ng/J to ppm at 3 percent O_2, for natural gas multiply the ng/J value by 1.96 (169 ÷ 86).

For residual and distillate oils, following the same methodology, the conversion factor is 1.78.

To convert from ppm NO_2 to lb $NO_2/10^6$ Btu for natural gas multiply by:

$$1/\left[\left(1.96\ \frac{ppm \cdot J}{ng}\right)\left(\frac{430\ ng}{1J} \cdot \frac{10^6\ Btu}{1\ lb}\right)\right] = 0.00119\ \frac{lb\ NO_2}{ppm\ NO_2 \quad 10^6\ Btu}$$

APPENDIX B

METHODOLOGY AND EXAMPLE CALCULATION FOR ESTIMATING ACT COST EFFECTIVENESS

$$\text{Cost Effectiveness} = \frac{\text{Total Annualized Cost}}{\text{Mass of } NO_2 \text{ emissions reduced/year}}$$

Annualized Cost = Annualized Capital Cost + Annual Operating Cost

Annualized Capital Cost = (Capital cost for equipment installation or other one-time charges) x capital factor

Annual Operating Costs = Annual incremental maintenance cost + Annual increased energy costs

Annual Maintenance Costs = Replacement parts cost + labor cost, etc.

Annual increased fuel costs are calculated using an appropriate price for fuel and the known or estimated increased fuel consumption.

To determine "mass of NO_2 emissions reduced per year," the mass of NO_2 per unit of heat energy input for the appropriate fuel is calculated as follows:

(ppm baseline - ppm controlled) x appropriate conversion factor (see Appendix A)

= lbs. of $NO_x/10^6$ Btu fuel heat energy input*

Using this value, the mass of NO_2 emissions reductions per year is determined as follows:

---

*NO_x calculated as NO_2

$$\frac{\text{lbs. of } NO_2}{10^6 \text{ Btu}}\left(\text{Rated Capacity in } \frac{10^6 \text{ Btu}}{\text{hr}}\right)\left(\frac{\text{hours of operation}}{\text{year}}\right)\left(\frac{1 \text{ ton}}{2000 \text{ lbs}}\right)$$

= Tons of emissions reduced/year.

The cost-effectiveness is arrived at by dividing total annualized cost by total tons of NO_x emissions reduced/year.

Sample Calculation for Glass Furnace NO_x Control:

Applicable technology: Low excess O_2 and electric boost for a gas-fired furnace. No costs are associated with reducing excess O_2. The example melter heat capacity is 75 x 10^6 Btu/hr heat input.

Annualized capital cost

Capital costs for electric boost equipment and installation costs are estimated to be \$250,000 x 1.42 = \$355,000. The 1.42 factor is for cost updating to extrapolate 1974 costs to 1979 costs (see Reference 40; Chemical Engineering, May 8, 1978, page 190 and August 13, 1979, page 7 which are the sources of the cost factors).

An annualized capital cost factor of 0.25 is used which assumes a 15 year lifetime and a 12 percent interest rate resulting in a 14.7 percent capital recovery factor, 6.7 percent straight line depreciation factor and 4 percent allowance for taxes, insurance and overhead.

Under these assumptions, the annualized capital cost = 0.25 x 355,000 = \$88,750/yr.

Annual operating cost

Rebricking of the furnace is estimated to cost \$1,420,000 once every four years as compared to once every seven years without electric boost.

Annualized incremental maintenance costs are

$$= \frac{1{,}420{,}000}{4} - \frac{1{,}420{,}000}{7}$$

= \$152,142

The electric boost will require approximately 20,000,000 KW-hrs to supply 12 percent of the total yearly energy input. Assuming a cost of \$0.03/KWh, the energy cost for electric boost is:

20,000,000 x 0.03 = \$600,000.

The 12 percent energy usage of 75 x 10^6 Btu/hr glass furnace is now substituted. Assuming the furnace operates 8000 hrs per year and is gas-fired with gas priced at \$2/10^6 Btu, the savings will be:

75 x 0.12 x \$2 x 8000 = (\$144,000)

Total annualized cost

Therefore, the total annualized cost is the sum of annualized capital and operating cost:

\$ 88,750
152,142
600,000
(144,000) savings
\$696,892.

Mass of NO_2 emissions reduced/year

The range of uncontrolled emissions is 490 to 700 ppm and the controlled emissions are 192 to 219 ppm. Therefore, for the furnaces emitting uncontrolled emissions of 490 ppm and controlled emissions of 192 ppm, the emissions reduction is 298 ppm, or in lbs $NO_2/10^6$ Btu:

$$\text{ppm } NO_2 (490 - 192)\ (0.00119)^* \frac{\text{lbs}}{\text{ppm } 10^6 \text{ Btu}}$$

$$= 0.354 \text{ lb of } NO_2/10^6 \text{ Btu}$$

Emissions reduction in tons/year:

$$(0.354)\ (75)\ (8000)\left(\frac{1}{2000}\right)$$

$$= 106.7 \text{ tons of } NO_2/\text{year.}$$

---

*See Appendix A for derivation of this factor.

Cost effectiveness

Cost effectiveness = \$696,892/106.7 ton of NO_2 per year

= \$6531/ton of NO_2 reduced.

For furnaces emitting 700 ppm (uncontrolled emissions) and 219 ppm controlled emissions, the emissions reduction in $lbs/10^6$ Btu:

$$= (700 - 219)\ (.00119)^*$$

$$= 0.572\ lb/10^6\ Btu$$

or in tons/yr:

$$(0.572)\ (75)\ (8000)\left(\frac{1}{2000}\right)$$

$$= 171.6\ \text{tons/year.}$$

$$\text{Cost effectiveness} = \frac{\$696{,}892}{171.6}$$

= \$4061/ton of NO_2 reduced.

Thus the range of cost effectiveness is \$4000/ton to \$6500/ton

Sample Calculation for Utility Boiler:

The sample calculation is for a gas-fired 1488 x 10^6 Btu/hr (436 MW thermal) heat input boiler using combined combustion modifications to achieve NO_x levels of 100 to 150 ppm at 3 percent excess oxygen.

Annualized capital cost

For a 90 MW electrical boiler, Reference 1 gives \$5.6/kW electrical (\$5.6 kW_{el}) cost (1977 basis). For a 436 MW thermal or 145 MW_{el} (assuming six-tenths-factor rule and a 1977 to 1979 15 percent cost index factor) the 1979 cost is:

$$\frac{(5.6)\ (90)}{145}\left(\frac{145}{90}\right)^{.6}(1.15) = \$5.3/kW_{el}.$$

---

*See Appendix A for derivation of this factor.

Reference 4 gives \$11/kW$_{el}$ (1978 basis) for any size. On a 1979 basis, the cost is 11(1.09) = \$12/kW$_{el}$. This gives a range of \$5.3 to \$12/KW$_{el}$ for capital costs. For a 50 percent load factor, the annualized capital cost (25 percent used to annualize capital cost; see glass furnace calculation example) ranges from:

$$\frac{(5.3)\ (.25)\ \frac{\$}{\text{KWyr}}}{(0.5)\ (24)\ (365)\ (\text{hrs/yr})} = \$0.00031/\text{kWh}$$

to $$\frac{(12)\ (.25)}{(0.5)\ (24)\ (365)} = \$0.0007/\text{kWh}.$$

Annual operating cost

The additional fan power is taken to be 0.5 percent of the unit's rating (Reference 1) and assumed to be electricity at 30 mills/kWh.

$$\left(145000\ \frac{\text{kWh}}{\text{hr}}\right)\left(\frac{0.03\$}{\text{kWh}}\right)(0.005) = \$21.75/\text{hour}$$

$$\frac{21.75\ \frac{\$}{\text{hr}}}{145000\ \frac{\text{kWh}}{\text{hr}}} = \$0.00015/\text{kWh}$$

References 1 and 4 give the additional maintenance per year as 5 percent of the capital cost and based on the lower capital cost estimate is:

$$\frac{(5.3)\ (0.05)\frac{\$}{\text{kWyr}}}{(0.5\ (24)\ (365)\ \frac{\text{hrs}}{\text{yr}}} = \$0.00006/\text{kWh}$$

Reference 1 gives the fuel use penalty as 0.75 percent of the unit's rating which is:

$$\left(1488\ \frac{10^6\ \text{Btu}}{\text{hr}}\right)(0.0075)\ \left(2.00\ \frac{\$}{10^6\ \text{Btu}}\right)\left(\frac{1\quad \text{hr}}{145000\ \text{kWh}}\right) = \$0.00015/\text{kWh}$$

The total operating cost is then the sum of the additional fan power, maintenance and fuel use penalty costs; just calculated:

$$\begin{array}{r} \$0.00015 \\ 0.00006 \\ 0.00015 \\ \hline \$0.00036 \text{ kWh} \end{array}$$

However, another source (Reference 4) assumes a higher 1 percent fuel penalty, which gives the following fuel penalty:

$$1488\ (0.01)\ (2)/145000 = \$0.00020/\text{kWh}.$$

Based on the higher capital cost esimtate, the additional maintenance cost per year is:

$$\frac{(12)\ (0.05)}{(0.5)\ (24)\ (365)} = \$0.00015/\text{kWh}$$

A higher total operating cost is then determined using the higher maintenance and fuel penalty costs just calculated and fan power cost used previously:

$$\begin{array}{r} \$0.00015 \\ 0.00015 \\ 0.00020 \\ \hline \$0.00050/\text{kWh} \end{array}$$

Total annualized cost

Therefore using the annualized capital and operating cost estimates, the total cost per year ranges from:

$$\begin{array}{lrcr} & \$0.00031 & & \$0.0007 \\ & 0.00036 & & 0.0005 \\ \cline{2-2} \cline{4-4} & \$0.00067/\text{kWh} & \text{to} & \$0.0012/\text{Kwh} \\ \text{or} & 0.67 \text{ mills/kWh} & \text{to} & 1.2 \text{ mills/kWh} \end{array}$$

Cost Effectiveness

The baseline is 350 to 800 ppm, therefore the cost effectiveness ranges from:

$$\frac{(0.00067\ \$/\mathrm{kWh}_{\mathrm{el}})\left(2000\ \frac{\mathrm{lb}}{\mathrm{ton}}\right)}{(800 - 150\ \mathrm{ppm})\left(.00119\ \frac{\mathrm{lb}/10^6\ \mathrm{Btu\text{-}in}}{\mathrm{ppm}}\right)\left(10000\ \frac{\mathrm{Btu\text{-}in}}{\mathrm{kWh}_{\mathrm{el}}}\right)} = \frac{\$180}{\mathrm{ton}}$$

to $$\frac{0.0012}{(350 - 100)}\ \frac{10^6 \cdot 2000}{(0.00119)\ (10000)} = \$810/\mathrm{ton}$$

APPENDIX C

GLOSSARY OF TERMS

Air Register Adjustment -- A combustion technique in which the air registers of burners are adjusted to deliver fuel-rich or air-rich fuel/air mixture to the burners to control NO_x formation.

Air-to-Fuel Change -- A combustion technique in which the ratio of the mass flowrate of air to the mass flowrate of fuel is changed in an internal combustion engine to control NO_x formation.

Available Control Technology (ACT) -- This term is used to describe any stationary source NO_x emission retrofit control technology or technique for which data are available for at least one test for the category or subcategory of equipment being considered for NO_x emission control. Such an ACT designation should not be construed to mean that the application of such control technology is necessarily reasonable. Additional testing, analysis and study may be necessary in order to make such an evaluation concerning reasonableness.

Baseline (or Base Case) Emissions -- This refers to the NO_x concentration in the emissions category or subcategory prior to the application of ACT.

Biased Burner Firing -- An off-stoichiometric combustion technique in which the lower rows of burners of a wall-fired boiler are fired more fuel-rich than the upper rows of burners. This may be accomplished by maintaining normal air distribution to the burners but distributing more of the fuel to the lower rows of burners than the upper rows. This results in the upper rows of burners firing air-rich thus ensuring complete combustion with a concurrent NO_x emission decrease.

Burners Out of Service (BOOS) -- An off-stoichiometric combustion technique in which individual burners, or rows of burners, admit air only. This allows the fuel admitting burners to fire more fuel-rich since a portion of air normally admitted through the fuel admitting burners is being admitted through the air only burners. Thus the fuel admitting burners are firing more fuel-rich than usual, with the remaining air required for complete combustion being admitted through the air only burners.

Combined Combustion Modifications -- The incorporation of two or more combustion modifications.

Combustion Modifications -- Control techniques involving an alteration of the normal burner/firebox configuration and/or operation used to reduce NO_x formation.

Derate -- A NO_x control technique which limits the maximum load of an engine to less than the design value.

External Exhaust Gas Recirculation -- A combustion modification for internal combustion piston engines in which a portion of the exhaust gases are routed back to the engine air intake to displace some of the inlet air resulting in reduced gas temperature and oxygen concentration thereby reducing NO_x formation.

Firetube Boiler -- A steam or hot water generator with heat transfer occuring from hot combustion gases flowing within steel tubes to the water flowing over these tubes.

Flue Gas Recirculation (FGR) -- A combustion modification in which a portion of the flue gas from the economizer outlet is extracted and returned to the furnace either through the furnace hopper, through the burner windbox, or both. FGR inhibits NO_x formation by reducing the bulk furnace gas temperature and oxygen concentration in the combustion zone.

Load Variation -- A NO_x control technique which allows steam or heat generating equipment to be fired at varying fuel and air amounts.

Low Excess Air -- A combustion technique in which combustion air is reduced to the minimum amount necessary for complete combustion. With less oxygen available in the combustion zone, both thermal and fuel NO_x formation are reduced. This technique is usually the first NO_x control technique tried.

Low NO_x Burners -- Burners designed to control NO_x formation by reducing flame turbulence, delaying fuel/air mixing, and establishing fuel-rich zones where combustion initially takes place. This is a departure from usual burner design which emphasizes high turbulence, high intensity, rapid combustion flames. The longer, less intense flames produced with low NO_x burners result in lower flame temperatures which reduce thermal NO_x production. Furthermore, the reduced availability of oxygen in the initial combustion zone inhibits fuel NO_x generation.

Low O_2 and Electric Boost -- A combined combustion technique used in the glass manufacturing industry to control NO_x formation. Lack of excess combustion oxygen (O_2) limits NO_x creation while arcing electricity between electrodes through the molten glass (boosting) supplies energy without burning fuel at the melter.

Manifold Air Cooling -- A NO_x control technique in which the temperature of the intake air to an engine is cooled. An intercooler is usually used.

Noncatalytic Ammonia Injection -- A control technique in which ammonia is injected at high temperatures (930 to 980°C) into flue gas to chemically reduce NO_x to nitrogen.

Off-Stoichiometric Combustion (OSC) Techniques -- Techniques used to control NO_x by carrying out initial combustion in a primary, fuel-rich, combustion zone and then completing combustion, at reduced temperatures, in a second, fuel-lean zone. Biased burner firing, burners out of service, and overfire air injection are all forms of OSC.

Overfire Air (OFA) -- An off-stoichiometric combustion technique in which the burners are fired more fuel-rich than normal while admitting the remaining combustion air through overfire air ports or an idle top row of burners. This is also referred to as "Two-Stage Combustion."

Reduced Air Preheat -- A NO_x control technique in which the combustion air delivered to a boiler has had its temperature reduced.

Reduced Load -- A combustion technique in which the bulk gas temperature and, consequently, NO_x formation is reduced through load reduction, or derating. This technique is also called "Reduced Firing Rate."

Retard -- A NO_x control technique for internal combustion piston engines in which ignition of the fuel is delayed by delaying the spark (spark ignition engines) or the start of fuel injection (compression ignition engines).

Selective Catalytic Reduction Using Ammonia -- A flue gas treatment in which ammonia is injected at moderate temperatures (370 to 480°C) into flue gas and passed over a catalyst to promote the chemical reduction of NO_x to nitrogen.

Staged Combustion Air -- See Off-Stoichiometric Combustion.

Water/Steam Injection -- A combustion modification in which water/steam are injected into the combustion zone of an engine, turbine, steam or heat generator to reduce the flame temperature and subsequently reduce NO_x formation.

Watertube Boiler -- A steam generator with heat transfer occuring from hot combustion gases flowing over steel tubes to the water flowing within those tubes.

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